Want to Forecast Well Interference in Resource Plays? Try Using Flow Models

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Denver Chapter SPEE
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Why Are We Concerned About Interference?

• Investor-oriented articles suggest EUR overestimated in infill wells because interference was ignored
  ▪ Wall Street Journal 2019 articles
  ▪ Wood Mackenzie 2019 study and paper
• Industry studies indicate that close well spacing for infill wells and duration of production from primary wells can decrease EUR
  ▪ VSO 2019 analysis of Bakken well data
  ▪ Schlumberger model study (SPE 191799)
  ▪ Equinor model study (URTeC 2431182)
Studies Show Recovery Decreases With Closer Spacing in Eagle Ford

After SPE 191799 and URTeC 2431182
Well Spacing Affects Fracture Geometry in Eagle Ford Study

After URTeC 2431182
Well Spacing Affects Fracture Geometry

• Primary well “produced” for 400 days before infill well completed
• Model simulation provides insight into fracture patterns
  ▪ 400-ft spacing model shows asymmetric fracture network development skewed toward pressure sink created by parent well
  ▪ 800-ft spacing model shows much less interaction

After URTeC 2431182
How Can We Solve the Problem of Overestimating EUR for Infill Wells?

- Fundamental consideration: model interference properly
- Possible approaches
  - Rigorous reservoir simulation with coupled geomechanical model
    - Probably most accurate approach
    - Time-consuming, expensive, extensive input data requirements
  - Analytical solutions in RTA software
    - History match early (mostly transient) data for $k$, $x_f$
    - Vary well spacing to model interference effects
  - Empirical decline curves, TWP (type wells)
    - Models interference only if present in production histories
  - Rapid reservoir simulation: Science Based Forecasting (SBF)
Field Data Study: West Texas, Delaware Basin, Wolfcamp A

As of 09/2018

Legend
- Primary
- Infill
- Wells analyzed in this study

AOI

1 mi.
Fundamental Problem Illustrated: Primary 2 Outperforms Infill and Primary 1...What Can We Do Better in Future?

At 27 months
Primary 1: 160 MBO
Primary 2: 246 MBO
Infill 1: 178 MBO

Infill 1 11% > Primary 1
Infill 1 32% < Primary 2
Areal and GBV Views of Area of Interest

Areal

- Parent (Unbound)
- Infill (Fully Bound)

GBV

- Primary 2 (P2)
- Infill 1 (I1)
- Primary 1 (P1)

Distances:
- 1500’
- 1000’
How Does SBF Work?

• Provides physics-based approach to forecasting
• Uses observed reservoir, completion, production, pressure data
• Retrieves pre-run simulations as basis to history match primary well
  ▪ Selects candidate simulations from stored results with parameters in range of known parameters
• Forecasts future production of primary, infill wells
So How Do We Proceed?

- Create infill well model based on best matches of history
- Forecast future production for infill well(s)
- Some parameters based on primary well history match
- Other parameters based on match of shorter-duration history of infill well, allowing reasonable range of parameters from primary well match
- Study alternative infill well spacing, completion design with varied SRV
  - Learn how to improve results in similar situations in future
Blind Test Used to Validate SBF, Compare with DCA-Based TWP Analysis

• **Purpose**: Determine accuracy of SBF results

• **Methodology**
  - **Step 1**: Construct P50 type well using DCA profiles from wells in area
  - **Step 2**: History match primary well with simulation
    - Place ranges on primary well parameters
      - Account for uncertainty of parameters in infill wells
    - Generate simulated TWP for infill based on parametric ranges
    - Construct P50 TWP well (or other probabilities if desired)

• **Validation**: Compare cumulative production from
  - Reported production data
  - Forecast with DCA-based TWP
  - Forecast with SBF
Assumptions for SBF Blind Test

### Primary 1 HM
- Matrix $k$: 455 nD
- $x_f$: 262 ft
- $h_f$: 140 ft
- HF $k$: 8,200 mD

### Primary 2 HM
- Matrix $k$: 655 nD
- $x_f$: 526 ft
- $h_f$: 320 ft
- HF $k$: 9,000 mD

### Infill Ranges
- $x_f$: 262-526 ft
- $h_f$: 20-420 ft
- Matrix $k$: 455-655 nD
- HF $k$: 8,000-9,500 mD
- HF $S_{wi}$: 90% – 95%

### Additional Parameters
- Thickness: 200–350 ft
- Matrix $\phi$: 8%
- Matrix $S_{wi}$: 42%
Both DCA and SBF TWPs Match Observed 27-Month History for Infill Well

<table>
<thead>
<tr>
<th>P50 Cum Oil (MBO)</th>
<th>Actual I1</th>
<th>SBF I1</th>
<th>DCA</th>
<th>DCA 2018+</th>
</tr>
</thead>
<tbody>
<tr>
<td>At 27 Months</td>
<td>178</td>
<td>172</td>
<td>173</td>
<td>154</td>
</tr>
<tr>
<td>% Difference</td>
<td>-4%</td>
<td>-3%</td>
<td>-14%</td>
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SBF Accurately Estimates Infill Well P50 Cumulative Production

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- SBF and DCA accurately approximate Infill 1
  - 4% difference actual vs. SBF
  - 3% difference actual vs. DCA
- Cannot quantify effect of interference with DCA alone
So Why Use SBF? What Makes it Different from the DCA-Based TWP Approach?

With SBF, we can answer important questions:
• Could we have planned infill well spacing better?
• Could we have forecasted infill well production more accurately?
• Can we improve future infill wells that we drill?

With SBF, we can provide additional analysis techniques
• Pre- and post-drill TWP comparison:
  ▪ Is there an optimal spacing for our project? SBF analyzes well spacing
  ▪ How does an index called “Fracture-Driven Interaction“ (FDI) impact our infill production? SBF analyzes fracture interference
  ▪ Can we time our infills better? SBF analyzes timing of infill well drilling
Infill 1 (I1) Well Spacing Sensitivity Analysis

Base Case

Case 1

Case 2

Case 3

Case 4

Case 5

Case 6
**EUR Results for I1 - Spacing Sensitivity**

**Spacing from P1**
- Base Case: 1,000 ft
- Case 1: 600 ft
- Case 2: 900 ft
- Case 3: 1,200 ft
- Case 4: 1,500 ft
- Case 5: 1,800 ft
- Case 6: 2nd infill between I1 and P2

![Graph showing cumulative production over time for different spacing cases](chart.png)
EUR Results for I1 - Spacing Sensitivity

**Spacing Sensitivity**

**Optimal well spacing in Case 3**

**Spacing from P1**
- **Base Case:** 1,000 ft
- **Case 1:** 600 ft
- **Case 2:** 900 ft
- **Case 3:** 1,200 ft
- **Case 4:** 1,500 ft
- **Case 5:** 1,800 ft
- **Case 6:** 2\(^{nd}\) infill between I1 and P2

![Graph showing cumulative production in MBO for different cases](image)
Economic Analysis Shows Case 3 has Largest NPV and IRR

Economic Assumptions
Oil Price: $43/bbl
Gas Price: $2.50/Mscf
CAPEX: $8.5M/well
OPEX: $18,000/month
Discount Rate: 10%
Severance Tax Oil: 4.6%
Severance Tax Gas, NGL: 7.6%
Gas NGL Yield: 106.8 bbl/Mscf
Gas Shrink Factor: 53.22%
NGL Price: 23% of oil
Calculating Fracture-Driven Interaction (FDI) To Quantify Fracture Interference
Calculating FDI in Production Forecasting

**Half-LENGTHS of I2**

Base Case: no infill
Case 1: 2\textsuperscript{nd} infill, $x_f=424$ ft
Case 2: $x_f=200$ ft,
Case 3: $x_f=500$ ft
Case 4: $x_f=600$ ft
Using FDI to Quantify Fracture Interference of Infill 1

Half-LENGTHS of I2
Base Case: no infill
Case 1: 2nd infill, $x_f=424$ ft
Case 2: $x_f=200$ ft,
Case 3: $x_f=500$ ft
Case 4: $x_f=600$ ft
Using FDI to Quantify Fracture Interference of Infill 1

Half-Lengths of I2
Base Case: no infill
Case 1: 2\textsuperscript{nd} infill, $x_f=424$ ft
Case 2: $x_f=200$ ft,
Case 3: $x_f=500$ ft
Case 4: $x_f=600$ ft
Summary of Spacing and Interference Sensitivity Study Results

- Spacing impacts recovery of infill well
  - Largest increase in Case 3
    - Infill equidistant from both primary wells (P1, P2)
    - Interference occurs only if $x_f > 600$ ft
  - Least EUR and cumulative production in Spacing Case 5
- Increased FDI decreases recovery
  - Largest EUR in Interference Base Case: FDI = 0 Acre-ft, EUR = 543 MBO
  - Lowest EUR in Interference Case 4: FDI = 3,432 Acre-ft, EUR = 333 MBO
Conclusions

• Both DCA-based TWPs and SBF can forecast future production accurately for primary wells, at least up to time of interference
  ▪ DCA-based TWPs, SBF require comparable effort, have comparable cost
• SBF provides more accurate forecasts for infill wells, primary wells after wells interfere
• SBF provides basis for improving spacing, timing of future infill-drilling programs
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QUESTIONS?

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References

- USI Technology [https://www.techusi.com/](https://www.techusi.com/)
  - Email: info@techusi.com
History Matching of Primary Wells

• Obtain:
  ▪ Geological and petrophysical parameters
  ▪ Vertical and lateral distance
  ▪ Measured BHP
• Place in CMOST
• Get cases that match best for oil and BHP (gas and water matched secondarily)
• Large range of permeability: 30 nD – 10 μD
• Load matched HM cases into SBF
Infill Well Matching in SBF

• From HM cases loaded in SBF, remove outliers compared to infill production curve
  ▪ Left with a matched cases
• In Future Type Well tab, place range on the primary well parameters
  ▪ Ranges can be arbitrary (20% added, or we can take the highest and lowest values of the primary well ranges and use those as our min/max range)
• Obtain P50 type well based on the results from the above step
• Get a best matched case to actual infill production to then use in CMG to run sensitivities