Numerical and Laboratory Investigations for Maximization of Production from Tight/Shale Oil Reservoirs

FP00008115

George Moridis, Matthew Reagan, Tim Kneafsey, Marco Voltolini, Sharon Borglin, Asm Kamruzzaman, Zhi Li, Jonathan Ajo-Franklin

Lawrence Berkeley National Laboratory

Program Manager: Steve Henry

U.S. Department of Energy
National Energy Technology Laboratory
Oil & Natural Gas
2020 Integrated Review Webinar
Continue to work at multiple scales to quantify production-enhancing processes using parallel lab, imaging, and simulation capabilities.

**Area 1: Proppant Transport**

- We need to understand proppant behavior before we can predict it.

- **Laboratory studies** of proppant transport in fractures (and corners)
- **Expanded XRμCT visualization** of fractures and proppants
  - Understand how proppant determines **conductivity**
  - Understand role of **proppant shape** (reorganization)
  - Understand **creep/embedment** at higher temperatures
  - Micro-mechanical measurement of **matrix strength**
- **Coordination between simulations, lab-scale tests, and micro-scale visualization** (validation and ground-truthing)

- **Goal:** Incorporate proppant transport (with coupled geomechanics) into **TOUGH+OGB** to create predictive tools.
Overview and Technical Approach

Continue to work at multiple scales to quantify production-enhancing processes using parallel lab, imaging, and simulation capabilities

Area 2: Production Enhancement

• **Simulation studies** of production enhancement (reservoir scale):
  • Expand and use **TOUGH+OGB**: shale oil/gas all-purpose simulator
  • **Gas injection** (multiple species), **thermal enhancement**
  • Effect of oil gravity vs. injection fluids
  • Ongoing compendium of **best and worst production strategies**

• **Laboratory studies** of production enhancement:
  • Examine **anisotropic/heterogeneous** wetting media
  • Osmotic displacement (saline formations)
  • Technique combinations (pathwise) to avoid permeability jails
  • Targeted toward **verifying simulations**

**Project Performance Dates:** FY19 through FY21
**Budget:** $1.2M, $400K in FY2019, $400K in FY2020, $400K in FY2021
Understanding the mechanisms impacting conductivity evolution of a propped fracture

In propped fractures, many key mechanisms determining the fracture conductivity, and its evolution, are linked to small features: the proppant-shale and proppant-proppant contacts.

**The productivity** and the usable lifetime of a propped fracture is linked to the behavior of those contacts.

The nature of the interactions can be very variable in nature (chemical, mechanical, etc.), and generate impactful processes, such as embedment, shattering, etc. **Two examples:**

- **Chemical interaction:** $\text{CO}_2\text{(aq)}$ does not impact proppant-shale contacts (in red), but enhances fracture conductivity.
- **Mechanical interaction:** different response to stress of quartz and ceramic proppants.

**In situ dynamic X-ray micro-imaging** can identify and quantify such processes → Better and more reliable models → less need for expensive tests in the field

(Similar processes at the next larger scale are studied in S. Nakagawa’s topic)
Proppant behavior in shale fractures during forced closure: how does it affect conductivity?

We have studied different variables (type of proppant, type of shale, shale orientation, proppant thickness) and identified different processes and their impact on fracture conductivity evolution during fracture closure.

The 3 main processes highlighted in an Eagle Ford shale with quartz sand proppant:

1) The proppant rearranges and closes fast flow zones (highest impact on conductivity)
2) Proppant starts to break, causing the aperture to drop significantly
3) Collapse of the fracture with embedding and/or shattering of proppant

The calculated conductivity evolution can be divided into 3 parts:

Temperature-mediated creep in organics-rich oil shales

- Organic-rich shales are potentially excellent source rocks, but fracture lifetime can be extremely short.
- High temperature can significantly modify the mechanical properties of these shales and trigger ductile proppant embedment, consequently decreasing the conductivity very quickly.

At temperatures as low as 75 °C the behavior of the shale changes noticeably, and further changes as $T$ increases

- At 75 °C the fracture closing rate was 13 μm/h, contributing to a loss of fracture conductivity rate of 8.7%/h (closure of high-flow zones close to the contacts)

We can directly evaluate these phenomena, including proposed (field) techniques for aimed at modifying the mechanical properties of fracture surfaces to avoid embedment and loss of conductivity

Current work focuses on: 1) multi-layer and 2) generalization of the previous observations via micro-modeling.

- Conductivity curves are different, with the ceramic proppant being more efficient after the first breakage events.
- Rearrangement in multilayers becomes much less important, compared to monolayers.
- Calculated 4D Models, aiming at predictive capabilities → application to larger scale models!

**Multilayer model**

**Monolayer model**

**Normalized conductivity curves (embedment)**

**Normalized conductivity curves**

**Flow fields vertical profile**

(width frac closing cycle)
Quantitative EOR Experiments

Several EOR production strategies are investigated by injecting oil-soluble gases including helium (He), nitrogen (N\textsubscript{2}), methane (CH\textsubscript{4}), carbon dioxide (CO\textsubscript{2}), and mixtures of CH\textsubscript{4}/CO\textsubscript{2} of varying molar compositions.

Laboratory procedures:

1. Sample preconditioning with water vapor.
2. Sample pressure-saturation (at 1,500 psia) with \textit{n}-dodecane.
3. Gas-driven drainage of excess \textit{n}-dodecane (1,500 psia).
4. Soak with gas/gas-mixture of choice (1,500 psia).
5. Produce dodecane by depressurization (1,500-0 psia).
6. Change test variables and repeat the process.

Porous media consists of vertically stacked synthetic discs surrounded by high-conductivity matrix-fracture interfaces.

Weakly anisotropic water wetting (I) and anisotropic wettability samples.
EOR Experiments: Effect of Injectant

* Large mass of CO₂ required.

Weakly Anisotropic Artificial Composite (Matrix poresize 3.5-0.8 μm; matrix permeability 11.9-5.33 md)
EOR Experiments: Wettability Anisotropy and Poresize

Recovery vs. 1) wettability, 2) anisotropy, 3) poresize, 4) injected fluid composition

**Solvent: 67%CH₄/CO₂**

- Composite (primary production)
- Composite (EOR only)
- Ceramic (EOR only)
- Thermoplastics (EOR only)

<table>
<thead>
<tr>
<th>Poresize</th>
<th>Anisotropic Media 1</th>
<th>Anisotropic Media 2</th>
<th>Anisotropic Media 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1.2 μm poresize)</td>
<td>1.4</td>
<td>3.4</td>
<td>7.8</td>
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<tr>
<td>(n = 4)</td>
<td>2.4</td>
<td>2.6</td>
<td>6.4</td>
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<tr>
<td>(230 nm poresize)</td>
<td>4.1</td>
<td>0.73</td>
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<td>(n = 2)</td>
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**Solvent: 33%CH₄/CO₂**

- (70 nm poresize)
  - (n = 1)
- (230 nm poresize)
  - (n = 1)

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<tr>
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**EOR more effective for smaller pore sizes**

(Matrix poresize 230-70 nm; matrix permeability 0.5-0.003 md)
EOR Experiments: New Proppant Transport Visualization Tool

- Proppant behavior under various fracture geometries and fluid injections
- Numerous in-plane geometries tested as analogs
- Fracture roughness alteration next
Simulation Studies: **TOUGH+OilGasBrine (T+OGB) Code**

- Conventional and tight/shale oil/gas, enhanced oil recovery, **fully compositional, fully non-isothermal, 3D, porous/fractured media, multi-scale: mm to reservoir**
- 2 Oils, H$_2$O, Salt(s), up to 11 gas components (C$_{1-3}$, CO$_2$, N$_2$, H$_2$, etc.) + CH$_4$ hydrates
- Includes enhanced oil physical properties relationships (viscosity, etc.)
- Massively **parallel capabilities** (features merged with pTOUGH+)
- Coupled with the **Millstone** geomechanical code
- **240,000 – 850,000+ elements** and more (1 – 3 MM equations)
- Developed in this FWP, now utilized in other DOE research efforts (Multi-Lab HFTS)
Simulation Studies: Continuous CH₄ Drive

**Base case:**
- $Z_{\text{max}} = 15 \text{ m} (49 \text{ ft})$
- $Y_{\text{max}}/2 = 25 \text{ m} (82 \text{ ft})$
- $Y_{\text{frac}} = 20 \text{ m} (66 \text{ ft})$
- $X_{\text{max}}/2 = 15 \text{ m} (49 \text{ ft})$
- $Z_1 = 7.5 \text{ m} (25 \text{ ft})$

**SRV Case:**
- Extending 22 m into $Y_{\text{max}}/2$
- Covering $X_{\text{max}}/2$ and $Z_{\text{max}}$

**System Properties (from confidential industry data):**
- Reservoir depth: 2274 m (7460 ft)
- Constant bottomhole pressures: $P_{wp} = 138 \text{ bar}$, $P_{wi} = 317 \text{ bar}$
- Initial reservoir conditions: $P = 241.3 \text{ bars}$, $T = 73.9 \degree \text{C}$
- Bubble point: 142 bar, GOR: 670 SCF/BBL
- Shale permeability: $k = 1.1 \mu \text{D}$; **Stimulated volume (SRV):** $k = 5.5 \mu \text{D}$
- Hydraulic fracture permeability: $k = 1.4 \text{ D}$
- Shale porosity: 4%; SRV: 6%
- Oil: $\gamma_{\text{API}} = 38$; Gas: $\gamma_{\text{G}} = 0.68$
- **Injected gases:** CH₄ (CO₂, N₂)

1 mm to 0.25m discretizations:
- 420K elements, 1.68M equations

1: Base case (no SRV)  1i: Production + Injection (no SRV)
2: Production with SRV  2i: Production + Injection with SRV
3i: Production + Offset Injection (no SRV)  4i: Production + Offset Injection with SRV

**CO₂ drive, CO₂-based Huff-n-Puff: Under investigation**
Simulation Studies: Continuous CH$_4$ Drive

Case 2i: SRV (fracture, 2 matrix zones) + injection
Simulation Studies: Continuous CH$_4$ Drive, Offset Injection Well

Case 4i: SRV (fracture, 2 matrix zones) + offset injection
Simulation Studies: Water, Gas, and Oil Production

1: Base production case (no SRV)
2: Production with SRV
2i: Production + Injection with SRV
3i: Production + Offset Injection (no SRV)
4i: Production + Offset Injection with SRV

1i: Production + Injection (no SRV)

- Production a function of $k$ (matrix, SRV, etc.)
- SRV dominates production

Current evidence: not promising!
Reservoir Simulation Studies: Thermal EOR

**Injection well:** Unperforated, heat injection well

**Base case:**
- $Z_{\text{max}} = 10 \text{ m} \ (32.8 \text{ ft})$
- $Y_{\frac{\text{max}}{2}} = 30 \text{ m} \ (98.4 \text{ ft})$: System A
- $Y_{\text{frac}} = 20 \text{ m} \ (65.6 \text{ ft})$
- $X_{\frac{\text{max}}{2}} = 6 \text{ m} \ (19.7 \text{ ft})$
- $Z_1 = 5 \text{ m} \ (16.4 \text{ ft})$

**No SRV, No heat loss to boundaries**

**Cases:**
- A1: Heat injection at onset of production
- A2: 2 months preheating + all production period
- A3: 3 months preheating + all production period
- A4: 6 months preheating + all production period

1 mm to 0.50m discretizations: 240K elements, 960K equations
Thermal EOR: $k = 150 \text{ nD}, T_{hw}=250^\circ \text{C}$
Relative difference in Oil, Water, & Gas: Rates & Cumulative Production against Reference Case

Thermal EOR: \( k = 150 \text{ nD}, T_{hw}=250^\circ C \)
Reservoir Simulation Studies: Conclusions

- **Continuous gas injection** does not appear to increase oil production in shale/tight oil reservoirs the production period covered by this study because of...
  - Limited penetration of the injected gas into the ultra low-k formation
  - Short-circuiting of displacement by preferential flow of injected gas into the hydraulic fracture
- Gas production: increases significantly because of the injected gas, **but no net increase**
- Oil production: **practically unchanged**
- Offset injection well: decrease in the EOR performance

- Observations consistent and applicable to similar systems: with/without SRV, higher/lower matrix permeability
- **Generally applicable results or case-specific? Current evidence: not promising!**

- **Thermal EOR methods** appear ineffective in shale reservoirs with limited natural fracturing
  - No significant improvement of recovery over realistic time frames, even under ideal conditions
  - Reliance on the slow heat conduction and the large thermal inertia of shale/tight oil reservoirs
  - Low porosity, large density and specific heat of the porous medium
Summary: Accomplishments and Impacts

Since original project inception in 2014 we have:

- Identified the mechanisms governing production from shale oil systems from molecular to field scale
- Investigated a wide range of production enhancement strategies, evaluated their performance, and identified those that are not promising
- Currently investigating promising possibilities
- Investigated proppant transport, proppant behavior, and the effect of proppant/fracture interactions on conductivity and production
- Communicated results to industry:
  - Multiple presentations of results at oil & gas focused conferences
  - Multiple SPE conference papers now available on OnePetro
  - Multiple papers in review for publication in industrial focused/industry leading journals

- Built coordinated capabilities for the future: laboratory and simulation
Appendix
## Gantt Chart

<table>
<thead>
<tr>
<th>Project Year</th>
<th>#1</th>
<th>#2</th>
<th>#3</th>
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<tbody>
<tr>
<td>Quarter</td>
<td>Q1</td>
<td>Q2</td>
<td>Q3</td>
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<tr>
<td><strong>Task 1: Project Management and Planning</strong></td>
<td>M1</td>
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<tr>
<td>Task 2: 3D Modeling of the Transport and Long-Term Fate of Proppants</td>
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<td>M2</td>
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<tr>
<td>Task 3: Laboratory-Scale Studies of Proppant Transport</td>
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<td>M2</td>
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<tr>
<td>Task 4: In-situ 4D X-ray micro-imaging of the evolution of propped fractures</td>
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<td>M2</td>
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<td>Task 5: Reservoir Simulation of Recovery-Enhancing Production Techniques</td>
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<tr>
<td>Task 6: Laboratory-Scale Studies of Production Enhancement</td>
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**Budget:** $400K in FY2019, $400K in FY2020, $400K in FY2021
Plans for future development/commercialization

- The project is a fundamental research project, but the results can and will be published in industry-directed journals.
- The results as-presented are of immediate interest to industry.
- The simulation capabilities will be available to industry via the LBNL licensing process or via partnerships and work-for-others projects funded at LBNL by industry.
Organization Chart

George Moridis, Matthew Reagan PIs

Laboratory Studies
  Tim Kneafsey, Sharon Borglin, Marco Voltolini, Asm Kamruzzaman

Reservoir Modeling
  George Moridis, Matthew Reagan, Zhi Li