Characteristics of the “Big Three” Best Productive Tight Oil Plays in the USA:

Bakken, Eagle Ford, and Wolfcamp

Daniel M Jarvie, Wildcat Technologies/TCU Energy Institute

Acknowledgements

- AAPG
- Wildcat Technologies
- TCU Energy Institute
- Center for Petroleum Geochemistry, University of Houston
- Geomark Research and...
Who led the development of unconventional shale gas and tight oil plays?

Independent Oil Companies

<table>
<thead>
<tr>
<th>Company</th>
<th>Market Cap ($billions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mitchell Energy</td>
<td>3</td>
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<tr>
<td>Devon Energy</td>
<td>9</td>
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<tr>
<td>Southwestern</td>
<td>1</td>
</tr>
<tr>
<td>EOG Resources</td>
<td>45</td>
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<td>Chesapeake</td>
<td>3</td>
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<td>Marathon</td>
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<tr>
<td>Hess</td>
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</tr>
<tr>
<td>Apache</td>
<td>8</td>
</tr>
<tr>
<td>Anadarko</td>
<td>36</td>
</tr>
<tr>
<td>Oxy</td>
<td>45</td>
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</table>

Acknowledgements

Introduction

Background

Tight Oil Systems
- Bakken Formation Unconventional Tight Oil System
- Eagle Ford Unconventional Tight Oil System
- Permian Basin Multiple Unconventional Tight Oil Systems

Synopsis
Introduction

Generalized Characterization of Resource Oil Plays

- Eagle Ford
- Barnett
- Tight Mudstone
- U. Bakken Shale
- Austin Chalk
- Fractured
- Hybrid Tight
- Middle Member Bakken
- Wolfcamp
- Niobrara
Generalized Characterization of Resource Oil Plays but overlap in most

- Middle Member Bakken
- Wolfcamp
- Niobrara

- Tight
- Mudstone
- Hybrid Tight
- Fractured

- Eagle Ford
- Barnett
- U. Bakken Shale
- Austin Chalk

Sources: EIA, Petroleum Supply Monthly

Why the Big 3?

- Rest of USA
- USA GOM
- Permian region
- Eagle Ford region
- Bakken region

Sources: EIA, Petroleum Supply Monthly
Average Well Costs by Play 2015

- Bakken: $5.9 million
- Eagle Ford: $6.5 million
- Midland Basin: $7.2 million
- Delaware Basin: $5.2 million

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016

Background
**Oil Crossover Effect**

\[
\frac{S1}{TOC} > 1 \quad \text{or when} \quad \text{Oil Saturation Index (S1/TOCx100)} > \quad 100 \text{ mg oil/g TOC,}
\]

"Oil Crossover"

Data from Lopatin et al., 2003; Jarvie, 2012 AAPG Memoir 97; Jarvie, 1984, 2001

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**Importance of Thermal Maturity in oil producibility from tight rocks**

Many Producibility Factors
- Maturity
- System type
- Alteration
- Permeability
- Barriers/Breakthrough
- Simulation approach

Approx. %RoE:
- 0.5
- 0.6
- 0.7
- 0.8
- 0.9
- 1.0
- 1.1
- 1.2
- 1.3
- 1.4
- 1.5
- 1.6

Optimum window for tight oil
Optimum window for open-fracture shale
Optimum window for high btu shale gas
Lean-to-dry gas
Why Thermal Maturity is important in Tight Oil Plays: oil mobility

Bulk Oil Composition

<table>
<thead>
<tr>
<th>Hydrocarbons</th>
<th>Non-hydrocarbons</th>
</tr>
</thead>
<tbody>
<tr>
<td>-Saturates</td>
<td>-Resins</td>
</tr>
<tr>
<td>-Aromatics</td>
<td>-Asphaltenes</td>
</tr>
</tbody>
</table>

Source Rock

Kerogen

Early Petroleum

Petroleum (bitumen)

Asphaltenes

Resins

Aromatics

Saturates

Black Oil

Gas

Asphaltenes

Resins

Aromatics

Saturates

Volatile Oil

Gas

Resins

Aromatics

Saturates

Condensate

Gas

Aromatics

Saturates

Cracking of oil resins and asphaltenes yields a lighter, more mobile oil with higher saturates, API gravity and GOR.

Decomposition of Petroleum Resins results in higher amounts of saturates and resulting increase in API gravity

\[ y = -1.4575x + 90.323 \quad R^2 = 0.958 \]

\[ y = -0.2225x + 47.217 \quad R^2 = 0.9219 \]

Data from Han et al. 2014
Prediction of Fluid Saturation

HAWK-PAM
Light Oil to Heavy Oil and Kerogen

Fluid saturation by volume:
sum of Oil-I (Py1.1), Oil-I (Py1.2), Oil-II (Py1.3), & Oil-III (Py1.4)

Maendle, 2015

Pepper, 2019

Wettability Impact of resins and asphaltenes

Diagrammatic Resin

Highly aromatic with nitrogen, sulfur, and oxygen

Hydrogen Bonding enhanced in:
- -OH
- -SH

Such bonding allows resins to weakly bond to water.
Produced Oil vs Oil in Source Rock from which oil was produced

Produced Oil

Source/Reservoir Rock

It is important to understand the petroleum in the reservoir rock; surface oil is variably fractionated, sometimes highly fractionated

Current Source Potential and product type

Whether immature or mature, this graphic shows the original (if immature or restored) and the current remaining potential of a source rock and the product generated.

With maturation (as shown with the Barnett Shale data), the potential starts high and generates black oil, whereas at high thermal maturity the remaining potential is much lower and for gas.

This also shows that HI and TOC must be considered in tandem in assessing the source rock potential, i.e., a high TOC with low HI is still a poor source rock - a low TOC with high HI has petroleum potential limited only by thickness.
The “Big Three” show high original petroleum generation potentials.

- U. Bakken Shale is ca. 40 ft thick
- Eagle Ford is ca. 225 ft thick
- Wolfcamp is ca. 1000 ft thick

The “Big Three” U.S. Tight Oil Plays

- Middle Bakken Formation, Williston Basin
- Permian Basin Wolfcamp et al.
- Eagle Ford Gulf Coast
Williston Basin Middle Member Bakken Formation Play

The “Oreo cookie” system: Organic-lean carbonates juxtaposed to very organic-rich U. and L. Bakken Shale

Basin-wide Bakken Formation Data

These data reflect a range of thermal maturity values across the Williston Basin.

The high Bakken Shale values reflect low maturity, whereas the low values reflect about 1%Ro maximum.

The Middle Member is always lean and the bulk of the TOC and HI is from any oil in the interval.
Jarvie, Wildcat Technologies, Bakken, Eagle Ford, and Wolfcamp Tight Oil Plays

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The Parshall prospect was shown and rejected by 13 companies due to the immaturity of the Bakken Shales above the Middle Member. EOG Resources took the prospect and developed it into one of the largest fields in the basin.

What was unusual about the prospect was that despite the shales being low to early mature, there was high oil saturation in the Middle Member as well as the low maturity shales.

Oil migrated into the Middle Member from nearby more mature Bakken Shales but was also supplemented by oil from the shales themselves.

Which begs the question: which is more important thermal maturity or oil saturation?

Jarvie et al., 2011
Produced Oil shows low and high maturity fingerprinting results

Low molecular weight light hydrocarbons show low maturity based on CTemp, MPI, and yields of 1-1,2-DMCP and heptane

High molecular weight biomarkers of oil and extract show quite different thermal maturities

Geochemical Logs of EOG Resources
Parshall Field well, Williston Basin (ND)

1. High carbonate in Middle Member, very low in shale
2. Very high TOC in U. and L. Bakken Shales (ave. ~15%)
3. Oil content are very high in shale, fair in Middle Member
4. Restored oil contents very high in Middle Member
5. Oil crossover throughout Middle Member and Scallion; high OSI in shales (ave. 80 mg oil/g TOC)
6. Adsorption index is very high in shales; very low in Middle Member
7. Productive oil index is very high in Middle Member, fair in Scallion, and very low in shales
8. HI values occur in Middle Member but from oil content not kerogen
9. Tmax values decrease substantially over trend line in shales due to S1' carryover into S2
Bakken GC Fingerprints

Bakken Shale retains light hydrocarbons comparable to dead oil sample indicative of high sorptive affinity due to high TOC.

Middle Member has very low retentive affinity, indirectly indicative of excellent producibility.

GC = gas chromatographic

Understanding Lab Measured Pyrolysis Oil Yields

Standard Pyrolysis Yields

<table>
<thead>
<tr>
<th>S1 Oil</th>
<th>S2 (kerogen)</th>
</tr>
</thead>
</table>

Pyrolysis Yields after Extraction

Missing Oil S1’ (Evaporative Losses)

<table>
<thead>
<tr>
<th>S1 Oil</th>
<th>S2 extracted rock</th>
</tr>
</thead>
</table>

S1’ (oil in S2)
But a major portion of petroleum is lost before reaching the lab

**Black Oil**

Evaporative Loss of oil ($S_1'$)

$S_1$ Oil

$S_2$ extracted rock

$S_1''$ (oil in $S_2$)

**Light oil or condensate**

Evaporative Loss of oil ($S_1'$)

$S_1$ Oil

$S_2$ extracted rock

$S_1''$ (oil in $S_2$)

Total Petroleum Yield = $S_1'$ + $S_1$ + $S_1''$

Major loss in light oils (up to 90%)

Restore using exponential fitting of unevaporated $n$-alkanes

Restoring Lost Petroleum (only applicable to volatile oils and condensates)

Extract GC Histogram of Molar Yields of normal Alkanes
Extract GC Histogram of Molar Yields of *normal* Alkanes

![Histogram of Molar Yields of normal Alkanes](image1)

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Extract GC Histogram of Molar Yields of *normal* Alkanes with exponential fit of C15-C40 alkanes

![Histogram of Molar Yields of normal Alkanes with exponential fit](image2)

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**Restoring Lost Petroleum**
(applicable to volatile oils and condensates)

Extract GC Histogram of Molar Yields of normal Alkanes; logarithmic scale allows direct comparison of slopes

\[ y = 634.94e^{-0.227x} \]
\[ R^2 = 0.9882 \]

**Restoring Lost Petroleum**
(applicable to volatile oils and condensates)

Fully restored GC Histogram of Molar Yields of normal Alkanes, C1 to C40

- C6- 75%
- C7+ 25% typical of black oils (>12%)
Result of Restoration

**Oil exponential factor equal to Extract of Middle Member**

**Restored Middle Member Oil**

- Formula: $y = 707.95e^{0.029x}$

**Restored Middle Member Extract**

- Formula: $y = 122.67e^{0.21x}$

---

### M. Bakken Completion Data

<table>
<thead>
<tr>
<th>Well Parameters</th>
<th>Unit</th>
<th>Elm Coulee</th>
<th>Parshall</th>
<th>New Fairway</th>
<th>Periphery</th>
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<tbody>
<tr>
<td>TVD</td>
<td>Ft</td>
<td>10,069</td>
<td>10,169</td>
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<td>30</td>
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<td>Horse Power</td>
<td>Hp</td>
<td>14,049</td>
<td>15,135</td>
<td>13,573</td>
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<tr>
<td>Casing, liner, tubing</td>
<td>Ft</td>
<td>31,504</td>
<td>32,494</td>
<td>35,108</td>
<td>32,849</td>
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<td>Drilling days</td>
<td>Days</td>
<td>27</td>
<td>24</td>
<td>26</td>
<td>25</td>
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<tr>
<td>Natural proppant</td>
<td>MM Lbs.</td>
<td>1.86</td>
<td>4.13</td>
<td>3.77</td>
<td>1.78</td>
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<tr>
<td>Artificial proppant</td>
<td>MM Lbs.</td>
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<td>0.46</td>
<td>0.42</td>
<td>1.78</td>
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<tr>
<td>Total Water</td>
<td>MM gal.</td>
<td>2.89</td>
<td>4.37</td>
<td>3.63</td>
<td>3.3</td>
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<tr>
<td>Total Chemicals</td>
<td>Gal</td>
<td>144,497</td>
<td>218,649</td>
<td>181,413</td>
<td>164,968</td>
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<tr>
<td>Total Gel</td>
<td>Lbs.</td>
<td>115,598</td>
<td>43,730</td>
<td>36,283</td>
<td>32,964</td>
</tr>
</tbody>
</table>

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016
Eagle Ford
Gulf Coast

South Texas Eagle Ford Shale Location Map and Stratigraphy

Modified from ShaleExperts
Jarvie, AAPG Int’l, Buenos Aires, Argentina
2019: The Big Three Tight Oil Plays

Eagle Ford Play and Oil Phases

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016

Segregation of Various Eagle Ford Play Areas

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016
Gas-to-Oil Ratios (GOR) in Eagle Ford

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016

Eagle Ford Shale, South Texas, USA

Kerns Trough has ideal pressure and reservoir conditions:
- Condensate window
- Porosity 7 to 12%
- Permeability 0.4 to 1.2 µD
- TOC > 4%

Maverick Basin thickens to west, where reservoir quality is poor:
- Oil window
- Porosity 5 to 8%
- Permeability 0.2 to 0.8 µD
- TOC 2 to 4%

Northeast Oil is very thick, but has lower reservoir pressure and quality:
- Oil window
- Porosity 4 to 8%
- Permeability <0.3 µD
- TOC 1.5 to 3%

Modest TOC values in most productive area
Eagle Ford Outcrops and well data

Outcrops are Boquillas formation collected along US 90 near Comstock, Texas.

Well data are from Grabowski (1995), Robison (1997), and Noble (1998).

First indication of producible oil in Eagle Ford Shale from published data (Jarvie, 2007)

Data from Grabowski, 1985, 1995; Robison, 1997; Noble et al. 1998

10% of published data show oil crossover

However, oil crossover is not always present in producing wells especially in cuttings from archived well samples.
Restoring Evaporative Loss ($S1'$)

(see restoration of Bakken Middle Member)

Generalized example of restoration...

<table>
<thead>
<tr>
<th>Resolved GC peak area results:</th>
<th>50</th>
<th>units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Restored GC peak area results:</td>
<td>100</td>
<td>units</td>
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<tr>
<td>Difference:</td>
<td>50</td>
<td>units</td>
</tr>
<tr>
<td>Evaporative loss:</td>
<td>50%</td>
<td></td>
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<tr>
<td>$S1$ measured:</td>
<td>2.31</td>
<td>mg oil/g rock</td>
</tr>
<tr>
<td>Restored $S1$:</td>
<td>4.62</td>
<td>mg oil/g rock</td>
</tr>
<tr>
<td>Oil content:</td>
<td>53</td>
<td>boe/af</td>
</tr>
<tr>
<td>Oil content corrected:</td>
<td>106</td>
<td>boe/af</td>
</tr>
</tbody>
</table>

Additional Shale Samples show crossover after restoration

51% of samples show crossover (some off-scale)
High Molecular Weight Waxes

High molecular weight waxes are found in numerous oil plays, e.g., Eagle Ford, Gulf of Mexico, Vaca Muerta.

High molecular weight waxes (\(n-C_{20}\)) found in some shale plays and GOM.

Peak areas are more indicative of yield than height (area>height)

Dealing with Oil-Based, Polymer, or Water-Based Mud Contamination

GC fingerprint is dominated by OBM, but \(C_{20}+ n\)-alkanes indicative of native oil; in cases light ends are native oil (e.g., volatile oils, condensates)

Very small exponential factors (-0.527 and -0.637) are nonsensical indicative of refined product.
Removing Oil-Based, Polymer, or Water-Based Mud Contamination

Selective slope factor of -0.136 is indicative of black oil (<40°API), not volatile oil or condensate.

Note slope change and poor fit.

Eagle Ford Completion Data

<table>
<thead>
<tr>
<th>Well Parameter</th>
<th>Unit</th>
<th>Low Energy</th>
<th>NLE Core Energy</th>
<th>Western Curve</th>
<th>Gassy Edge</th>
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<tbody>
<tr>
<td>TVD</td>
<td>Ft</td>
<td>8,098</td>
<td>10,857</td>
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<td>Ft</td>
<td>6,264</td>
<td>5,469</td>
<td>5,819</td>
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<td>Psi</td>
<td>4,859</td>
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<td>22</td>
<td>20</td>
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<tr>
<td>Frac break pressure</td>
<td>Psi</td>
<td>6,802</td>
<td>9,120</td>
<td>7,120</td>
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<td>Pumping rate</td>
<td>Bpm</td>
<td>57</td>
<td>70</td>
<td>95</td>
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<td>Horse Power</td>
<td>Hp</td>
<td>10,929</td>
<td>17,994</td>
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<td>Casing, liner, tubing</td>
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<td>Days</td>
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<td>20</td>
<td>18</td>
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<tr>
<td>Natural proppant</td>
<td>MM lbs</td>
<td>4.93</td>
<td>7.04</td>
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<td>Artificial proppant</td>
<td>MM lbs</td>
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<td>1.67</td>
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<td>Total Water</td>
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<td>5.89</td>
<td>5.71</td>
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<td>Total Chemicals</td>
<td>Gal</td>
<td>441,793</td>
<td>256,958</td>
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<td>Total Gel</td>
<td>lbs</td>
<td>58,906</td>
<td>57,102</td>
<td>58,83</td>
<td>6,853</td>
</tr>
</tbody>
</table>

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016
Permian Basin is comprised of three structural areas: Delaware Basin, Central Basin Platform, and Midland Basin

Stratigraphic nomenclature

Source: ShaleExperts, 2016
Permian Basin Diagrammatic Cross Section

Comparison of Production in Delaware and Midland Basins

Delaware Basin, NM
751,000
563,000

Delaware Basin, TX
656,000
475,000

Midland Basin, TX
628,000
239,000

Rystad Energy Shale Intelligence 2018
Present-day HI versus Thermal Maturity: select Midland vs Delaware basins data

All sample are mid-to-late oil window in thermal maturity.
Variability reflects not only differences in thermal maturity, but the hybrid nature of these plays.
These data and related sigmoidal fit allow restoration of original TOC, HI, and S2 values for each individual sample.

Comparison of Restored Values for Delaware and Midland basins based on available data

Delaware basin

Midland basin

Average TOC: 2.2
Average HI: 521

Average TOC: 3.0
Average HI: 652
Multiple Organofacies, Mixing, Alterations, and Maturity Differences from oil chemistry

Wolfcamp: Correlation between diamondoids and quantitative aromatics

While diamondoids and aromatic maturity ratios agree in the Wolfcamp and many other plays, this is not always the case.

In some plays secondary charge of condensates result in a high diamondoid content on a lower maturity oil.

Using both aromatic maturity and diamondoids such mixing may be discerned.
GOR from Restored Yield of C$_7$+ hydrocarbons

![Graph showing correlation between Total C7 Hydrocarbons (wt.% of oil) and GOR (scf/stb)]

Source: Jarvie, 2017

Wolfcamp Completion Data

<table>
<thead>
<tr>
<th>Well Parameters</th>
<th>Unit</th>
<th>Bone Spring</th>
<th>Wolfcamp Delaware</th>
<th>Wolfcamp Midland</th>
<th>Spraberry</th>
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<tbody>
<tr>
<td>TVD</td>
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<td>Formation pressure</td>
<td>Psi</td>
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<td>6,386</td>
<td>4,771</td>
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<td>20</td>
<td>28</td>
<td>8</td>
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<tr>
<td>Frack break pressure</td>
<td>Psi</td>
<td>9,326</td>
<td>8,941</td>
<td>7,157</td>
<td>7,557</td>
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<td>70</td>
<td>59</td>
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<tr>
<td>Horse Power</td>
<td>Hp</td>
<td>18,401</td>
<td>14,869</td>
<td>15,735</td>
<td>12,993</td>
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<tr>
<td>Casing, liner, tubing</td>
<td>Ft</td>
<td>29,112</td>
<td>32,807</td>
<td>29,169</td>
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<td>Days</td>
<td>25</td>
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</tr>
<tr>
<td>Natural proppant</td>
<td>MM Lbs.</td>
<td>3.07</td>
<td>4.82</td>
<td>8.82</td>
<td>0.83</td>
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<td>1.39</td>
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<td>n/a</td>
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<td>6.25</td>
<td>8.74</td>
<td>0.77</td>
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<td>Total Chemicals</td>
<td>Gal</td>
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<td>312,658</td>
<td>436,836</td>
<td>38,545</td>
</tr>
<tr>
<td>Total Gel</td>
<td>Lbs.</td>
<td>186,294</td>
<td>182,595</td>
<td>87,367</td>
<td>7,709</td>
</tr>
</tbody>
</table>

Source: EIA, Trends in U.S. Oil and Natural Gas Upstream Costs, March 2016

Jarvie, Aapg Int’l, Buenos Aires, Argentina
2019: The Big Three Tight Oil Plays
Synopsis

- TOC and relative hydrogen content are equally important in assessing petroleum potential
- Thermal maturity-related decomposition of resins and asphaltenes provides mobile oil with sufficient gas push (pressure) to enable production
- Tight oil plays have variable forms (tight, hybrid, fractured) and combination of these forms
- HAWK-PAM can predict API and oil saturation
- TOC, S2, and HI may be restored utilizing sigmoidal fitting of available data over a wide maturity window
- S1 (petroleum content) may be restored using GC fingerprinting
- GOR may be predicted from light hydrocarbons and restoration of GC yield of alkanes
- Completion data shows the inherent variability of tight oil plays and the need for customization

Thank you!

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References


Pepper, A., 2019, AAPG ACE presentation.