Ryder Scott Company
Reservoir Evaluations in the Eagle Ford Shale
SPEE – Central Texas Chapter
SPE – Austin Chapter
November 3, 2015
Agenda

• Overview
• Geology and Petrophysics
• Completions
• Performance
• Economic Parameters
• Reserve Considerations
Active Producing Wells

Approximately 14,300 wells
Client Producing Wells

Approximately 9100 wells
Texas operators as of June have completed 11,542 wells, down from 15,828 wells recorded during the first half of 2014.

Here are the state’s top crude oil producers for June, in barrels:

1. Karnes (Eagle Ford) – 6,797,988
2. DeWitt (Eagle Ford) – 4,691,734
3. La Salle (Eagle Ford) – 4,620,430
4. Gonzales (Eagle Ford) – 3,156,164
5. Upton (Permian Basin) – 3,093,674
6. Andrews (Permian Basin) – 3,078,394
7. Midland (Permian Basin) – 3,052,231
8. Martin (Permian Basin) – 3,046,948
9. McMullen (Eagle Ford) – 2,922,426
10. Reeves (Permian Basin) – 2,527,124

Here are Texas’ top natural gas producers for June, by MCF:

1. Webb (Eagle Ford) – 58,555,033
2. Tarrant (Barnett) – 51,523,950
3. Panola (Haynesville Shale) – 27,740,460
4. Dimmit (Eagle Ford) – 23,321,147
5. Johnson (Barnett) – 23,049,439
6. DeWitt (Eagle Ford) – 20,807,735
7. Wise (Barnett) – 19,422,338
8. Karnes (Eagle Ford) – 18,571,638
9. Denton (Barnett) – 16,919,808
10. La Salle (Eagle Ford) – 15,679,814

Source: Houston Chronicle – Eagle Ford Shale tops list of top crude, gas producers – Jennifer Hiller
Geology

- Structure
- Log Response
- Hydrocarbon Pay Maps
Eagle Ford Shale

- Composed of Cretaceous aged sediments filling basins formed during the Laramide Orogeny.

- Depositional environment was low energy with a stable water column. High organic content of 3-5% was preserved due to anoxic conditions.

- Thermal degradation of the organics into hydrocarbon chains forced water out of the shale. These hydrocarbons eventually saturated the shale and seeped out, forming accumulations in overlying formations such as the Austin Chalk.

- The low permeability of the shale has allowed significant amounts of hydrocarbons to remain trapped in-situ.
Eagle Ford Shale

Figure 9. Southwest-northeast schematic strike cross section illustrating regional lithostratigraphic relationships across the Eagle Ford play area.

Hentz & Ruppel
Lower Eagle Ford Thickness

Figure 6. Isopach map of the lower Eagle Ford Shale. Cross section A-A' is shown in Figure 5. Note that areas of greatest thickness are the Maverick Basin and immediately northeast of the San Marcos Arch.

Hentz & Rupple
Figure 7. Isopach map of the upper Eagle Ford Shale. Cross section A-A’ is shown in Figure 5.
Structure Map

REGIONAL EAGLE FORD STRUCTURE

Contact: Bret Rothwell / Cell: 380-687-1084 / E-mail: BGROTH@HAL-PC.ORG

Geoscientists · Petroleum Engineers · Technical Analysts
Cross Section
Geology: Wells with Core TOC

- 208 Wells with log files
- 39 Wells with core data
- 16 Wells with core TOC data
\[ \text{TOC}_{\text{wt/wt}} = \left( \text{Vol}_{\text{ker}} \times \text{Rho}_{\text{ker}} \right) / (\text{RHOB} \times K) \]

\[ K = \text{Kerogen Conversion Factor (1.2)} \]

\[ \text{Rho}_{\text{ker}} \text{ ranges 0.9 (immature) to 1.4(very mature) g/cc} \]

Crain suggests default value of 1.26 g/cc
Petrophysical Workflow

- Presently dominated by core – log crossplot calibrations.
Petrophysical Workflow: TOC and RHOB

\[
TOCrhob = 55.134605 - 20.606903 \times RHOB
\]
Petrophysical Workflow: Corrected Porosity

Calculate kerogen corrected porosity for each curve

\[ \text{PHIDc} = \text{PHID} - (V_{\text{ker}} \times \text{PHIDker}) \]

\[ \text{PHINc} = \text{PHIN} - (V_{\text{ker}} \times \text{PHINker}) \]

\[ \text{PHISc} = \text{PHIS} - (V_{\text{ker}} \times \text{PHISker}) \]

We need to know PHIDker and Vker
Calculate kerogen corrected porosity for each curve

\[
PHIDker = \frac{(RHOma - RHOker)}{(RHOma - RHOfl)}
\]

\[
PHINker = .50 \text{ to } .65 \text{ (or from TOC / PHIN xplot)}
\]

\[
PHISker = \frac{(DTker - DTma)}{(DTfl - DTma)}
\]

(DTker 105 to 160 usec/ft or from xplot)

RHOma and RHOker can be determined using crossplots
RhoMa can be determined by plotting Core TOC and Core Bulk Density.

The X Intercept gives you your RhoMa value.

RhoMa = 2.64
RhoMa and RhoKer can also be determined by plotting Inverse Grain Density and Core Fraction TOC

First convert TOC wt% to TOC wt fraction

\[ \text{CorFracTOC}[] = \text{Core\_TOC}[] / 100 \]

; Reciprocal of Core Bulk Density

\[ \text{RecCorDen}[] = 1 / \text{Core\_BulkDensity}[] \]
RhoMa = 1 / Intercept

RhoToc = 1 / (Slope + Intercept)

RhoKer = RhoToc / K

\[ \frac{1}{\text{RhoMa}} = 0.381 \]

\[ \frac{1}{(\text{slope} + \text{intercept})} \times K = \text{RhoKer} = 1.138 \]
Now we have values for RHOker and RHOma we can calculate PHIDker and Vker:

\[
PHIDker = \frac{(RHOma - RHOker)}{(RHOma - RHOfl)}
\]

\[
Vker = \left[\frac{(TOCrhob / 100) \times (1.2 \times RHOB)}{RHOker}\right]
\]

Now we can calculate kerogen corrected porosity:

\[
PHIDc = PHID - (Vker \times PHIDker)
\]
Open question whether to use Archie equation or one of the various shaley sand equations

- Core porosity and saturation are total system measurements, calibration easier with Archie
- Assume $m = n$
  - Range could be 1.5 – 2.5
Core Expansion

Compare core bulk density to log bulk density to determine if significant “expansion effects”

Correct core porosity if needed

Core Expansion Correction

\[ \text{CorBlkVol[]} = \frac{1}{\text{Core\_BulkDensity[]}} \]
\[ \text{CorPorVol[]} = \text{Core\_Por[]} \times \text{CorBlkVol[]} \]
\[ \text{CorGrnVol[]} = \text{CorBlkVol[]} - \text{CorPorVol[]} \]

\[ \text{LogBlkVol[]} = \frac{1}{\text{RHOB[]}} \]
\[ \text{CorPorC[]} = \min(\text{Core\_Por[]}, \frac{(\text{LogBlkVol[]} - \text{CorGrnVol[]}]}{\text{LogBlkVol[]}}) \]

Correct for core water saturation if needed.

modified from Lapierre SPWLA
Petrophysical Workflow
Petrophysical Workflow
Petrophysical Results

• Found good agreement of RSC So*Phi*H log evaluation calculations with other company estimates.
• **So*Phi*H Maps** show the variation of in-place volumes across the field.

• The magnitude of **So*Phi*H** in an area generally correlates to average well production.

• **Good Log versus Core relationships** give good reliability of hydrocarbon-in-place estimates.
Upper EFS SoPhiH
Completions
Completions

- Lateral Length
- Pounds of Proppant
- Stages
- Initial Rates
Completions – Recent Karnes/Dewitt Wells

**Effective Lateral Length vs Stages**

- Equation: $y = 255.79x$
- $R^2 = 0.019$

**Lbs Proppant vs Eff LL**

- Equation: $y = 1375.7x$
- $R^2 = 0.5386$

**Lbs Proppant vs Stages**

- Equation: $y = 343035x$
- $R^2 = 0.729$

**Oil EUR vs BOPD IP**

- Equation: $y = 660.76x$
- $R^2 = 0.3615$
Performance

• Type Curves
• PVT
• Modelling
• Example
Well Defined Performance Example
Well Defined Performance Example
Erratic Performance Example
Complicating Factors

- Frac Hits
- Artificial Lift
- Choke Management
- Down Spacing
- Landing Interval
- Completion Method
- Production Allocations
- Measurement Points
Multiple Well Time Normalized
Multiple Well Time Normalized

**Q1:** 644 Bbl / D  
**Q13:** 122 Bbl / D  
**Eff De:** 81.1 %  
**EUR:** 369 MBO  
**Avg LL:** 5133 ft  
**MBOE:** 617 MBOE

Well Count: 35  
Longest Life # of Days: 826

**Normalized Days**

**Producing Days**

**Central Distribution - MBOE**

**Central Distribution – Oil / CND**

P50 = 516.7  
P50 = 360.1
Multiple Well Time Normalized

![Graph showing cumulative oil and gas production over normalized days.](image)

- **Cumulative Oil (MBO)**
- **Cumulative Gas (MMSCF)**

*Geoscientists · Petroleum Engineers · Technical Analysts*
Type Curve Performance

Cumulative Oil / Initial BOPD versus Days Produced

Actual Points consist of 6442 wells with Daily Production

Di is the first year decline rate

- Eagle Ford Wells
- b=1.2 D1=65 Dmin= 12
- b=1.2 D1=81 Dmin= 6
- b=1.5 D1=81 Dmin= 6
- b=0.9 D1=85 Dmin= 6
- b=2.0 D1=80 Dmin= 6
- Average

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PVT Properties

Fluid Properties & Maturation

Source: AAPG/DPA Reserves Forum 2015, Thomas G. Harris
PVT Wells
## PVT Analysis

<table>
<thead>
<tr>
<th>County</th>
<th>FormationTop</th>
<th>Oil API</th>
<th>Gas Gravity</th>
<th>Initial Pressure</th>
<th>Initial Temp</th>
<th>GOR</th>
<th>Yield</th>
<th>MW</th>
<th>Wellstream SG</th>
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<td>48.9</td>
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<td>4850</td>
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<td>282</td>
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<td>208</td>
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<td>16.873</td>
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<td>La Salle</td>
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<td>54.7</td>
<td>0.76</td>
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<td>291</td>
<td>9308</td>
<td>107</td>
<td>30.054</td>
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<th>C2</th>
<th>C3</th>
<th>C4-C6</th>
<th>C7+</th>
<th>Psat</th>
<th>RF Gas @1300psi</th>
<th>RF Oil @1300psi</th>
<th>Type</th>
<th>Shrink</th>
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<td>5.36</td>
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<td>7988</td>
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<td>59.00</td>
<td>12.40</td>
<td>5.92</td>
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<td>13.67</td>
<td>4584</td>
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<td>7.4%</td>
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<td>71.79</td>
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<td>5.49</td>
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<td>68.71</td>
<td>12.63</td>
<td>4.81</td>
<td>7.98</td>
<td>5.87</td>
<td>3910</td>
<td>63.9%</td>
<td>37.3%</td>
<td>RG</td>
<td>92.0%</td>
</tr>
</tbody>
</table>
PVT Analysis

\[
SG_{ws} = \frac{Rsi \times SG_g + 4584 \times SG_o}{Rsi + 132800 \times SG_o/Mo}
\]

\[
SG_o = \frac{141.5}{API + 131.5}
\]

\[
Mo = \frac{6084}{API - 5.9}
\]

\[
\frac{N_p}{N} = \frac{(Bo - Boi) + (Rsi - Rs) \times Bg}{Bo + (Rp - Rs) \times Bg}
\]
PVT Analysis

GOR and Oil Gravity versus In-situ Fluid Density

MW well stream / 28.97
# PVT Analysis

## Calculated Cumulative Recovery During Depletion at 210 °F

<table>
<thead>
<tr>
<th>Cumulative Fluid Recovery per MMScf of Original Dew Point Gas</th>
<th>Initial Gas in Place</th>
<th>Reservoir Pressure – psig</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(D.P.)</td>
<td>4807</td>
</tr>
<tr>
<td>Well Stream (Mcf)</td>
<td>1000.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>

* Normal Temperature Separation

- **Stock Tank Liquid (Bbls)**
  - Initial: 134.78
  - Intermediate: 0.00
  - Final: 8.19
- **Primary Separator Gas (Mcf)**
  - Initial: 899.18
  - Intermediate: 0.00
  - Final: 90.66
- **Second Stage Gas (Mcf)**
  - Initial: 0.00
  - Intermediate: 0.00
  - Final: 0.00
- **Stock Tank Gas (Mcf)**
  - Initial: 1.81
  - Intermediate: 0.00
  - Final: 0.12

<table>
<thead>
<tr>
<th>Corrected TotalGOR (Scf/STB)</th>
<th>6685</th>
<th>0</th>
<th>11091</th>
<th>14089</th>
<th>18274</th>
<th>24029</th>
<th>26791</th>
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<tr>
<td>Instantaneous TotalGOR (Scf/STB)</td>
<td>6685</td>
<td>0</td>
<td>11091</td>
<td>16941</td>
<td>28425</td>
<td>78301</td>
<td>44229</td>
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</table>

## Total Gallons of Ethane Plus (C₂H₆) Plant Products Produced In:

<table>
<thead>
<tr>
<th>Product</th>
<th>Gallons</th>
<th>(Scf/STB)</th>
<th>Gallons</th>
<th>(Scf/STB)</th>
<th>Gallons</th>
<th>(Scf/STB)</th>
<th>Gallons</th>
<th>(Scf/STB)</th>
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<tr>
<td>Well Stream</td>
<td>12644.56</td>
<td>0.00</td>
<td>1044.53</td>
<td>0.00</td>
<td>2503.21</td>
<td>0.00</td>
<td>4300.69</td>
<td>0.00</td>
</tr>
<tr>
<td>Primary Separator Gas</td>
<td>6960.86</td>
<td>0.00</td>
<td>699.50</td>
<td>0.00</td>
<td>1798.82</td>
<td>0.00</td>
<td>3324.17</td>
<td>0.00</td>
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<tr>
<td>Second Stage Gas</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
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<tr>
<td>Stock Tank Gas</td>
<td>27.14</td>
<td>0.00</td>
<td>1.81</td>
<td>0.00</td>
<td>3.98</td>
<td>0.00</td>
<td>6.32</td>
<td>0.00</td>
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</tr>
</tbody>
</table>

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PVT Analysis

Oil Recovery Factor %

Pressure

Multiples of Rsi of Gas EUR/Oil EUR

Pl = 10000 psi
Rsi = 857 scf/stb
Boi = 1.4412
Pbp = 2680 psi
Bop = 1.617
RF %bp = 10.87 %
Pressure and Temperature

Pressure and Temperature Versus Depth

Pressure = (Depth) * 0.6205

Temp = 74 + Depth / 100 * 1.85

DFIT is Diagnostic Fracture Injection Test
The Bo and Bg from PVT reports or correlations based on surface gravities.

SophiH was from our map.

Drainage area assumed to be well spacing times gross perforated interval length in feet.

Pressure and Temperature from TVD depth.
EUR Recovery Factors

Recovery Factors versus In-situ Fluid Density

Gas Recovery % OGIP
Oil Recovery % OOIP

MW well stream / 28.97
EUR Recovery Factors – LaSalle Black Oil

Recovery Factors versus In-situ Fluid Density

- Gas Recovery % OGIP
- Oil Recovery % OOIP

MW well stream / 28.97

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Performance Mapping

- Extract mapped values for:
  - Gmix
  - OOIP and BCF per Section
  - Oil Per Foot
  - Oil EUR
Oil per Foot Lateral
Oil EUR Map
The Oil and Gas EUR’s for producing wells determined using DCA on daily data.

There is a lot of room for interpretation based on the scatter of data.

Nearby wells that have more history may help guide projections.
PUD Analysis Methodology

- Bubble EUR plots are used for illustration purposes to help determine trends.
- PUD assignments were made by statistical analysis of the EUR’s and initial rates for a given area deemed to be analogous to the PUD area.
- May normalize wells based on lateral lengths or other completion parameters.
- Did not use volumetrics for determining the EUR’s, but as a cross check for reasonableness.
- RF % compared in the area of interest for consistency.
Example 1 – Bubble Map
Example 1 – Bubble Map
Example 1 – Probability Distribution
Example 1 – Oil EUR Map
Example 1 – Oil EUR Map vs Probability

- TC Gross Ult Oil (MBbls)
- Map Oil EUR
Example 1 – Recovery Efficiency %
New Development Schemes From Investor Presentations

Murphy

Pioneer

Marathon
New Development Schemes From Investor Presentations

Conoco

SM Energy
• Recovery Factors from expected model may be applied to proved volumetric in place estimates.

• Models may be used to support drainage area estimates

• Models may be used in combination with other estimates
Reservoir Modelling Results

- Black Oil
- Retrograde Gas
Reservoir Modelling Results

Oil EUR and Recovery Factor from Simulation Results
Versus Drainage Acreage
Drilling Unit PDP + PUD RF vs Acres/Well

- Proved RF%
- Proved Gas RF%
- Model Oil

Log. (Proved RF%)
Log. (Proved Gas RF%)
Log. (Model Oil)
Reservoir Modelling Results

Total Oil RF vs Acres/Well

- Graph showing the relationship between Total Oil Recovery Factor (RF) and Acres/Well.
- The data points are scattered across the graph, with a line trend showing the general trend.
- The x-axis represents Acres/Well ranging from 0 to 160.
- The y-axis represents the Total Oil RF ranging from 0% to 30%.

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Reservoir Modelling Results

Black Oil

EUR/MMBO vs Acreage

- OW1 MBO
- OW2 MBO
- Oil 3 MBO
- OW1 RF%
- OW2 RF%
- Oil 3 RF%
- Log. (OW1 RF%)
- Log. (OW2 RF%)
- Poly. (Oil 3 RF%)

Geoscientists · Petroleum Engineers · Technical Analysts
## Economic Parameters

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<th>Company</th>
<th>Abandonment</th>
<th>Salvage</th>
<th>Net</th>
<th>$/well</th>
<th>$/BO</th>
<th>$/MCF</th>
<th>$/BW</th>
<th>Drilling Cost</th>
<th>Lateral</th>
<th>Stages</th>
<th>$/LL</th>
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Drilling cost were for year end 2014
Current cost have been reduced by 20 to 25%
Reserve Considerations

17 CFR Parts 210, 211 et al and SPE 123793 John Lee

Reliable technology must have been demonstrated in practice to provide on a repeatable and consistent basis, reasonable certainty.

This demonstration must be based on persuasive empirical evidence from a reasonable sample size. Oil shale must have evidence that provides the basis for a geological model indicating continuous economic producibility out to a distance X feet from a control point in a given direction and to the distance from the control point to the filer claims to be proved.
Reserve Considerations

- Economic producing wells surrounding the area of interest
- Well log control surrounding area of interest that shows continuity of the reservoir
- Reasonable certainty of type curve
- Structure, Depth, T and P are well known
- PVT samples taken and compared to correlations
- Some model and volumetric analysis to establish drainage areas
- Completion parameters reviewed for consistency
Future Possibilities

- Geostatistics
- Kriging
- Variograms
- Interesting Paper- URTeC 2147795
  Improved Reserve Estimates Using Spatial Averaging
  (Shah and Kelker)
Questions

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