The U.S. Shale Gas Resource: Outlook for the Industry Reshaping Global Energy

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Supported by the Sloan Foundation, Mitchell Foundation, DOE, and oil&gas companies BEG’s team of geoscientists, engineers, statisticians and economists conducted an inter-disciplinary study of shale gas & oil resources.
Study Questions

To provide **rigorous and granular assessment of the future** we developed an integrated approach studying:

- What is the **original resource in place** (OGIP, OOIP)?
- What portion of the resource is **technically recoverable** in the past, present and future?
- What portion of the resource is **economically recoverable** given technical and economic assumptions?
- What are the **long-term production outlook** scenarios under various energy prices, costs, technology, regulations?
U.S. Natural Gas Turmoil

Gas Rigs Count vs. HH $/bbl

Gas Rigs
HH $/bbl

HH gas price $/MMBtu

Gas Rigs Count

HH $/bbl

Natural gas from shale and tight formations comprises ~50% of the U.S. consumption.

About 30% of gas is produced from tight and shale oil plays.

Despite the low natural gas prices, production continues to grow in many regions.
Production from Gas Plays only Grows

- Technology
- Economies of Scale
- Decreased rig costs (thanks to low oil prices)

Tcf/year

Barnett
Fville
Hville
Marcellus

Major Implication: Reduction in Emissions

Million Tonnes Carbon Dioxide

-10%

-16%

BP Statistical Review, 2016
Integrated Study Workflow

**Geologic Analysis**
- Reservoir characterization
- Original-Resource-in-Place mapping

**Well Decline Analysis**
- Production and its decline for gas/oil/water
- Stimulated/drained rock volume

**Recovery and Productivity Statistical Analysis**
Expected production as a function of
- Well productivity drivers
- Location and Completion
- Inventory of future wells
- Technically Recoverable Resources

**Well Economics**
Expected well profitability as a function of
- Well production profile
- Operational
- Market and regulatory parameters

**Production Outlook**
- Pace of drilling by year and area,
- Expected gas/oil/water production depending on economics, technology, regulation
Ikonnikova 2017

Barnett
Haynesville
Fayetteville
Marcellus
Eagle Ford
Bakken

BEG Shale Resource and Production Team

<table>
<thead>
<tr>
<th>Resource-in-Place</th>
<th>Tcf</th>
<th>Gas-In-Place</th>
<th>3100</th>
<th>Recoverable</th>
<th>700</th>
<th>Demand ‘16</th>
<th>27</th>
<th>Demand ‘06</th>
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<td>6,934</td>
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<td>HZ Wells drilled</td>
<td>-</td>
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</table>

HZ Wells drilled:
- 15,815

Demand:
- ‘16: 27
- ‘06: 22
N Horizontal Wells

- Drilled by 2017
- Left for future

- Total HZ wells drilled
  ~ 87,000
- Possible future drilling
  ~ 600,000
  + >1,000,000 in Permian
- 24 horizontals drilled within 1 year
- 2 adjacent pads 300 ft x 400 ft each
- Vertical separation about 80 ft
- Lateral well length is 6,000 - 7,000 ft
- Each well uses 8 - 10 MM lb of proppant
- HF water used is 6.5 - 8 MM gal per well
- Surface area used ~ 5 ac
- Subsurface area drained ~ 1,300 ac
- Total water used ~ 170 MM gal
- FP water 1st year ~ 7 MM gal
  following years ~2.5 MM gal
- Expected recovery of natural gas
  ~ 80Bcf/2bcm or 45% of gas-in-place
Well Economics Model

We use a standard discounted cash flow model to calculate

**Profitability Index: PI** = \[\frac{\text{Present Value of Expected Cash Flows}}{\text{Investment Cost}}\]

assuming a *price expected* at the time of drilling, 8% discount rate, and shut down period/economic limit determined by a positive cash flow, with

**Drilling and Completion:** \(DC \sim F\) (Depth, Length, Fluid, Proppant)

**Well production over time:** \(q_t \sim q^{\text{year}}\) (natural gas, liquids, water) \(\cdot\) Declineₜ
Per-well Production and its Decline

- geologic parameters,
- rock and fluid properties,
- completion design,
- technology

Patzek et al., 2013
Male et al., 2015
Variance in Reservoir properties

Depth to Top of Ordovician

- Oil
- Rich Condensate
- Lean Condensate
- Dry Gas
Differences in Declines across the Plays
Distributions of Individual Well Recovery

- Barnett
- Fayetteville
- Haynesville
Effect of Completions of Expected Recovery

Major producing regions in Marcellus

average well EUR for a given region (Bcf)

EURs assuming the same completion
EUR with a preferred completion
Use statistical tools:
- Random Forest
- Model-based recursive partitioning
To find Productivity Drivers

+ Energy Prices / Cost Indexes
Productivity Regions

Production Function:

$$EUR = f(GIP, \text{Completion}, \text{Age})$$

$$f = c \cdot W^{b_1} L^{b_2} P^{b_3} GIP^{b_4} \text{Age}^{b_5}$$

- 7 Production Regions, each region described by a single production function
- Regional splits:
  - gas / fluid properties
  - Pressure
  - time
- Change in functional parameters over time allows to analyze change in technology
### Model Performance

- New technology harder to predict initially, though some models adjust quicker
- Using larger training data does not necessarily result in better prediction in the presence of technology changes

#### Train-Test MSE

<table>
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<tr>
<th>Train</th>
<th>Test Year</th>
<th>MSE</th>
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<tr>
<td>2007-2014</td>
<td>2015</td>
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Mean Squared Error (MSE) based on cross validation used to assess model performance changes between years.
New Completion Strategies

- Established drilling patterns change with technological advances and new economic realm
- New drilling and completion techniques affects the cost and recovery reshaping the supply capabilities
- and supply elasticities

~80ft
25m
Drilling Approach and Results

- We find that operators often use not max NPV completions because of capital and land constraints.
- We use time & location dependent imputations to assign input factors and local geo attributes.

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Change in Productivity and Profitability: Haynesville Example

Number of potential locations

- 2012 Study
- 2017 Study

- 3$/MMBtu
- 4$/MMBtu
- more
Profitability

Haynesville Shale "Profitability History" Profitability Index based on Historical Data

Haynesville Shale Profitability Index $3.5/MMBtu and $55/bbl

Haynesville Shale Profitability Index $4.5/MMBtu and $55/bbl
Drilling Portfolio for Dry and Condensate

Dry and condensate area drilling portfolio of the Barnett shale play

Relative share of wells in the total portfolio

Profitability index, PI %

0 0.05 0.1 0.15 0.2 0.25 0.3 0.35

0.5 0.75 1 1.25 1.5 1.75 2 2.25 2.5 2.75 3 More

Inventory and Future Drilling

$N_t \text{ wells} \sim a \cdot \hat{p}_t^b \cdot N_{t-1}^c$

Drilling locations are assigned based on their PI, drilling portfolio and spacing availability.
Expected profitability of a well is a key indicator of investment attractiveness, depends on:

- Energy prices (natural gas, gas liquids, and oil),
- Drilling and Completion Cost (change with prices, technology, efficiency),
- Regulation (fiscal environment, drilling and production constraints),
- Expected well production given expectations about completions,
- Uncertainty
Outlook 3.5 $/Btu for natural gas and 50$/bbl for oil

Total: 36 Tcf
Assuming Increasing energy prices

Outlook assuming 4 $/Btu and 80$/bbl after 2017

- **History + Forecast**
- **Prediction**

Total: 43 Tcf
Production Projections

Annual production, Tcf/year

- Blue line: $3.5/MMBTU
- Red line: $4.5/MMBtu gas

<table>
<thead>
<tr>
<th>Tcf</th>
<th>New wells</th>
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<tr>
<td>$3</td>
<td>26</td>
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<td>$4</td>
<td>62</td>
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<tr>
<td>EIA</td>
<td>95</td>
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Projections for Different Prices

- Marcellus $3/MMBtu
- Hville $3/MMBtu
- Fville $3/MMBtu
- Barnett $3/MMBtu

Bcf/year

Projections for Different Prices

- All plays $4/MMBtu
- Marcellus $3/MMBtu
- Hville $3/MMBtu
- Fville $3/MMBtu
- Barnett $3/MMBtu
- All plays EIA prices

~380 TCF
~250 TCF
Summary

- Geologic and reservoir characteristics vary dramatically but 3D look helps us to understand the variability.
- Technology plays an important role in the basin dynamics and future production outlook, and so dynamic rigorous study is essential.
- Shale plays will continue their development even in the current price environment, supporting the U.S. natural gas and oil consumption.
- Environmental implications and infrastructure development are important and may constrain the development in the future, but preemptive actions can help.