OPTIMIZING DEVELOPMENT STRATEGIES TO INCREASE RESERVES IN UNCONVENTIONAL GAS RESERVOIRS

Prepared by:
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RPSEA Unconventional Gas
Conference 2011

April 19, 2011
Denver, Colorado

Project Overview

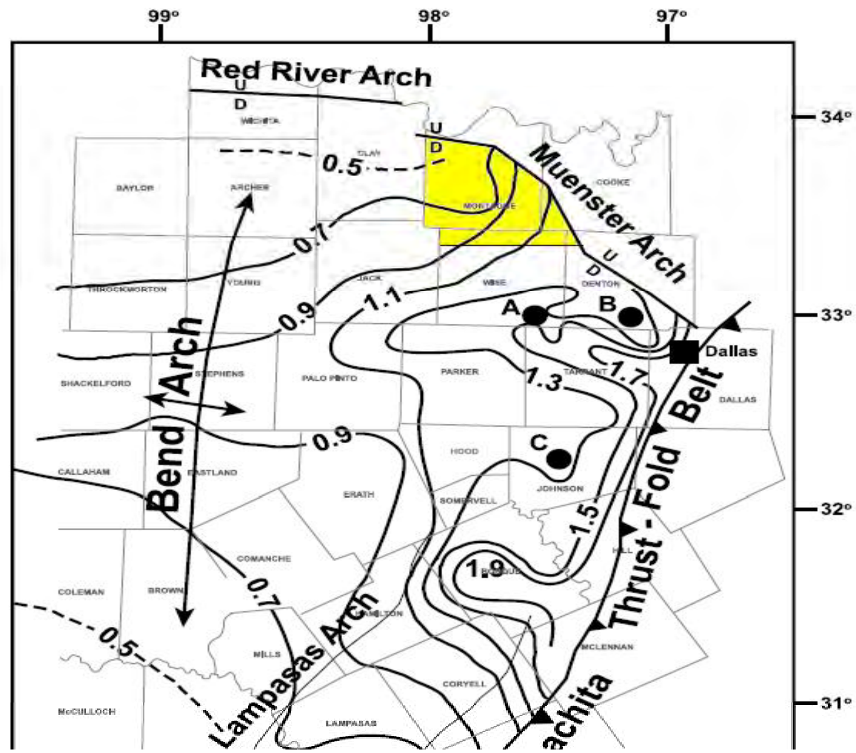
Objective: Develop new technologies for determining optimal development strategies in tight sand and shale gas reservoirs.

Core technology: Integrated reservoir and decision models that fully incorporate uncertainty in reservoir properties.

Application: University and industry partners to determine optimal well spacing and completion methods in the Barnett Shale formation in Cooke, Montague and Wise Counties, Texas, and the Gething tight gas formation in Alberta, Canada.

Impact: Technology incorporation into operators' development processes will enable reaching optimal spacing as quickly as possible, accelerating production and increasing reserves.

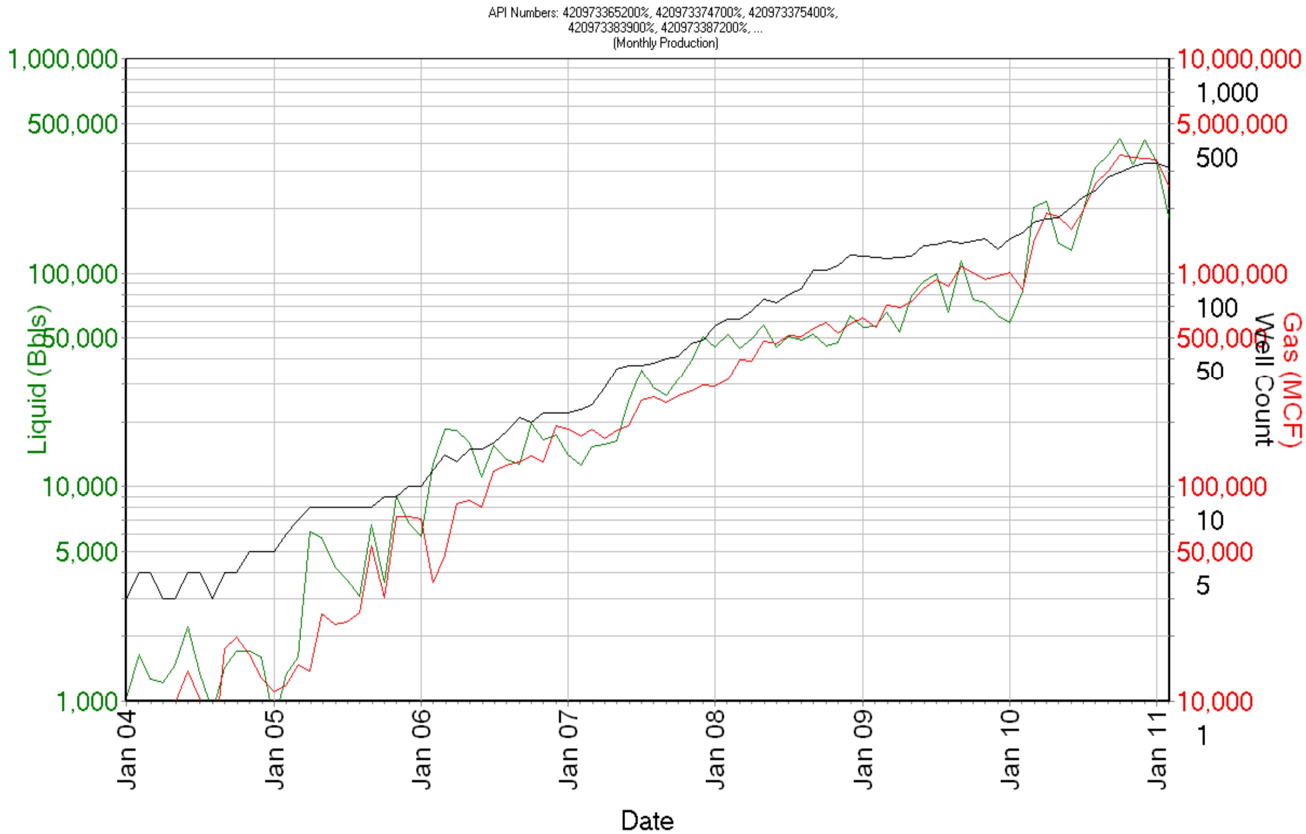
Our northern Barnett study area is in the oil window



Vitrinite reflectance map, from Montgomery et al. 2005

The study area is the northern part of Barnett shale in the Fort-Worth Basin, in Montague, Cooke and Wise counties (yellow area).

Overview of production history in study area



As of Feb 2011

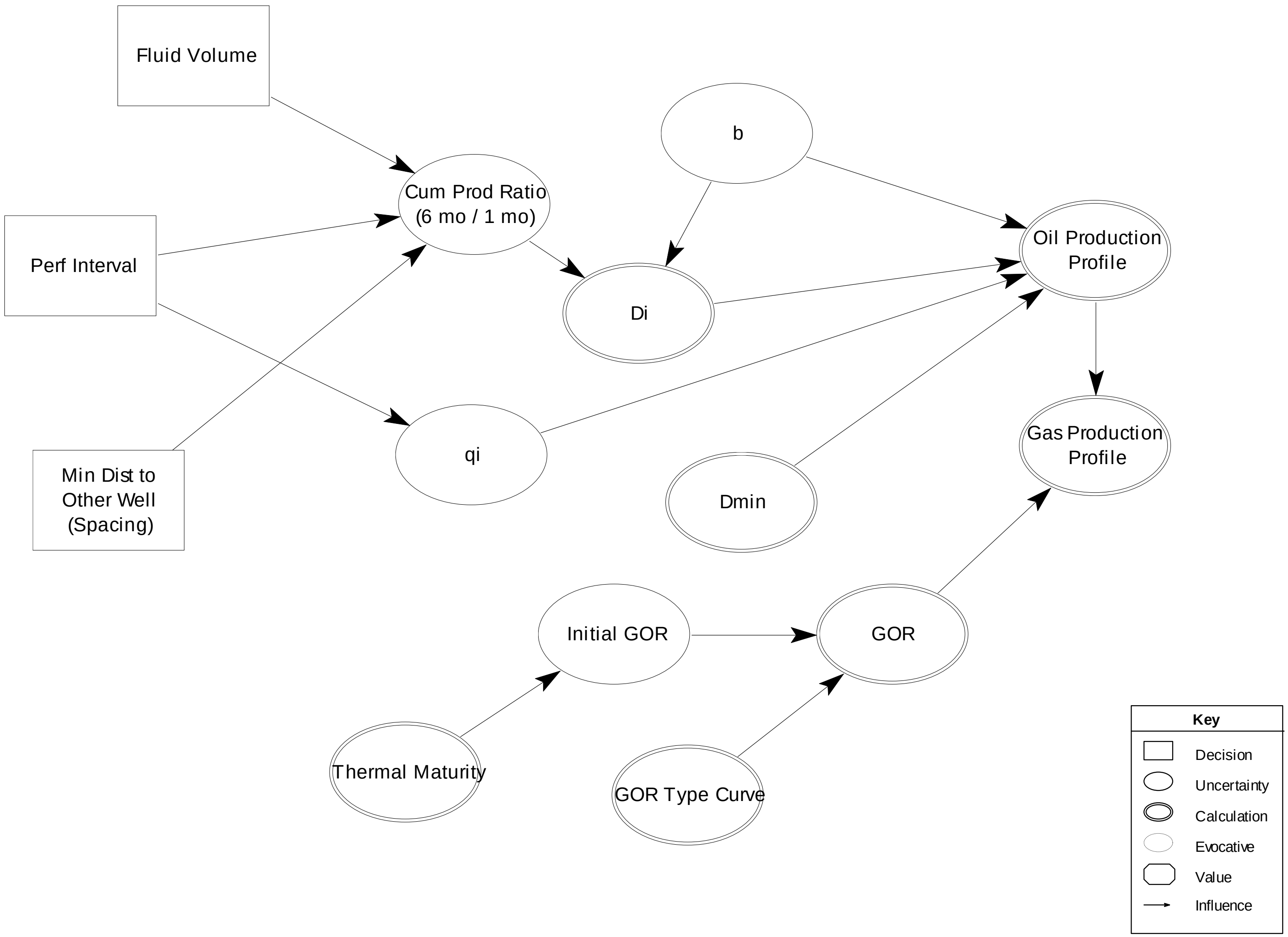
Well count: 252 horizontal wells have produced more than 1 month

Cumulative Oil: 6.26 Million bbls — Cum Oil/Well: 24,800 bbls

Cumulative Gas: 52.5 Bcf — Cum gas/Well: 0.20 Bcf

Cumulative GOR: 10 Mcf/STB

A decision diagram relates the development decisions we can make to production



Future work will include revenue and cost parameters.

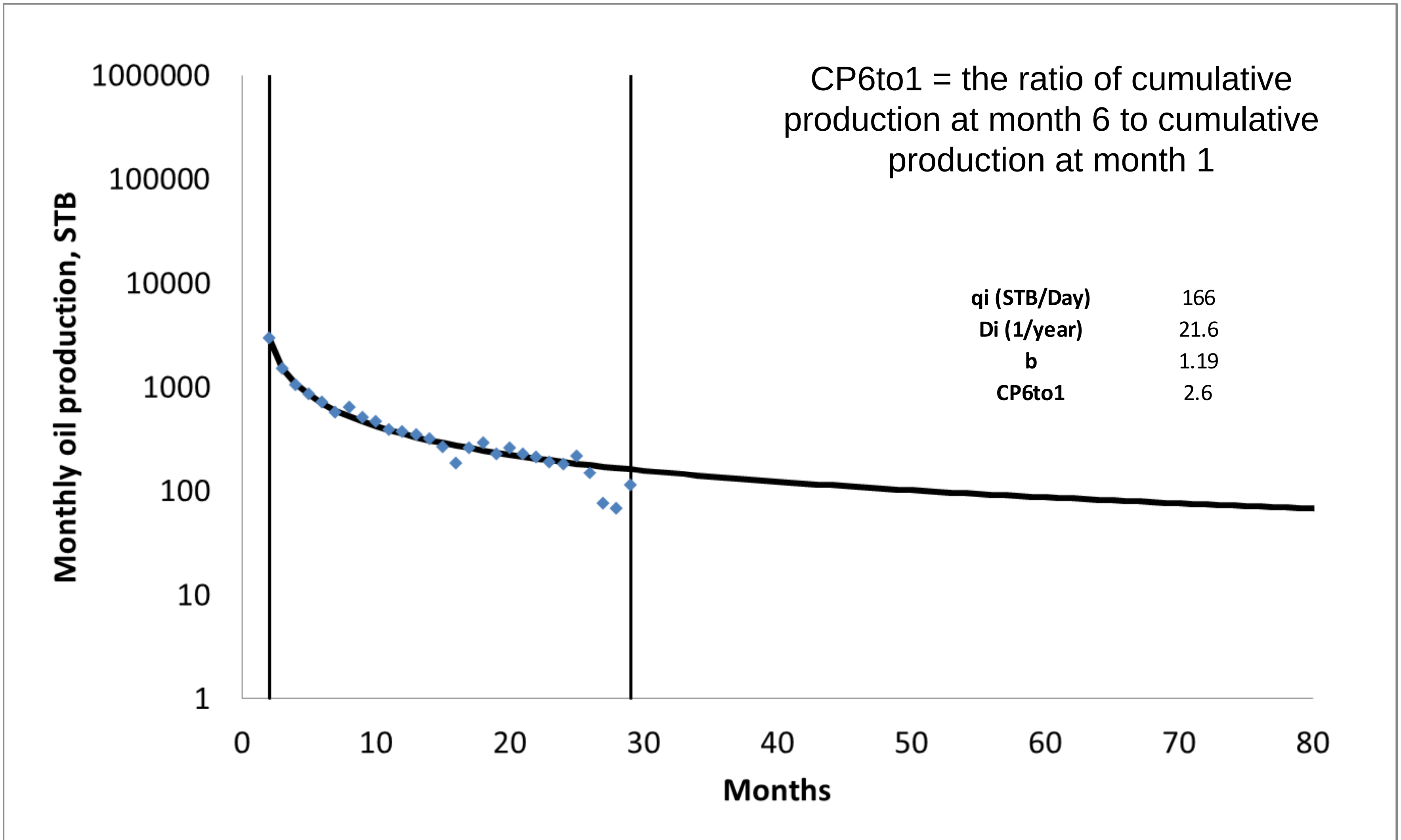
We constructed a preliminary decline-curve based reservoir model

Fit production declines for wells in study area

- 64 wells/leases were publicly available with
  - At least 6 months of production as of Jan 2011
  - Directional survey are available
- Used average production and parameters for leases with more than one well
- Determined least squares fit of q_i, D_i, and b.
- Restrictions: D_i <= 50/year and 0< b <2
  - The maximum b value for wells drilled before 1/1/2008 and produced until 3/1/2011 is 2.

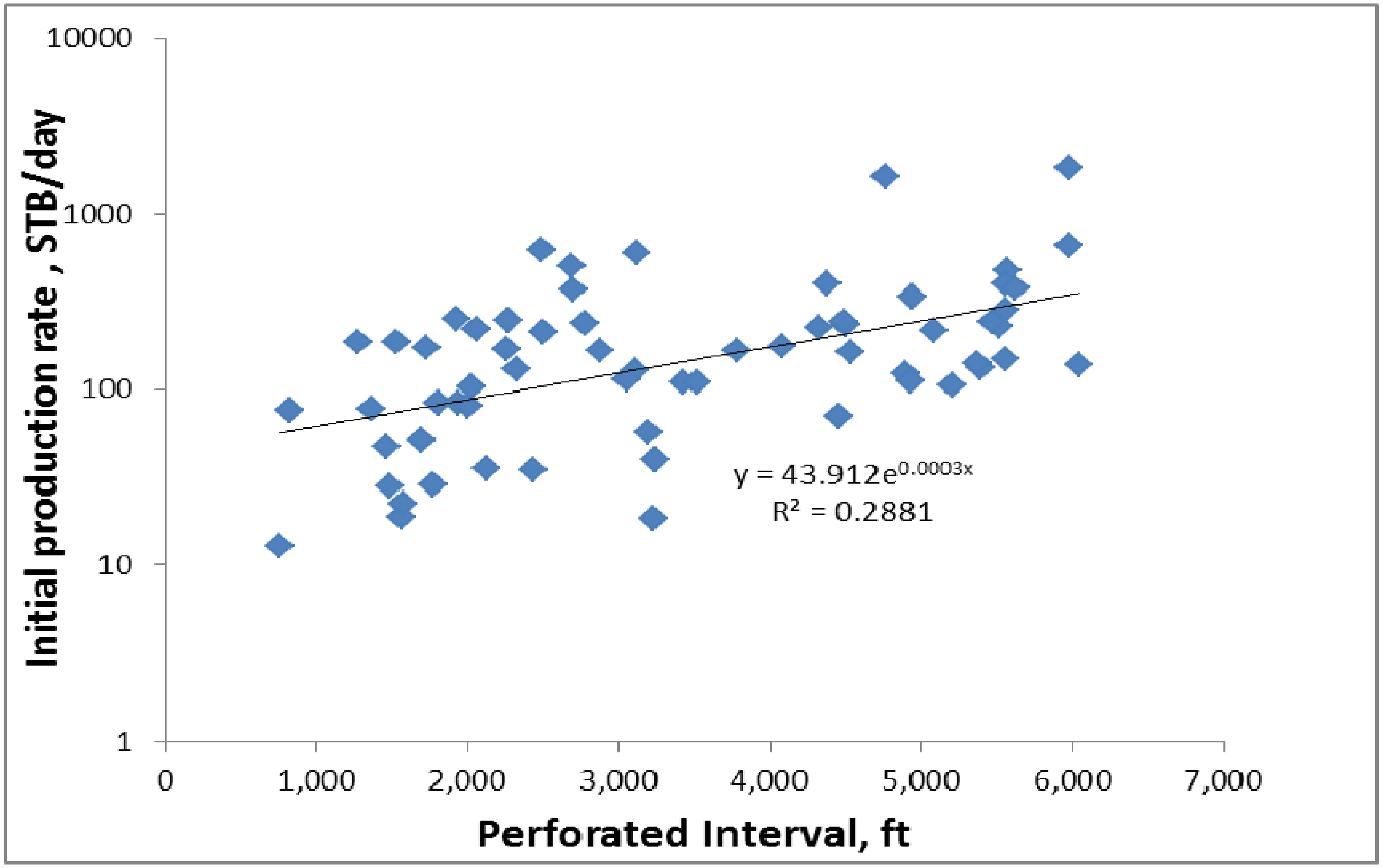
Conducted statistical analysis of decline curve parameters against completion parameters

Example individual-well decline curve match



Hyperbolic Decline Curve $q(t) = q_i(1 + bD_i t)^{-\frac{1}{b}}$

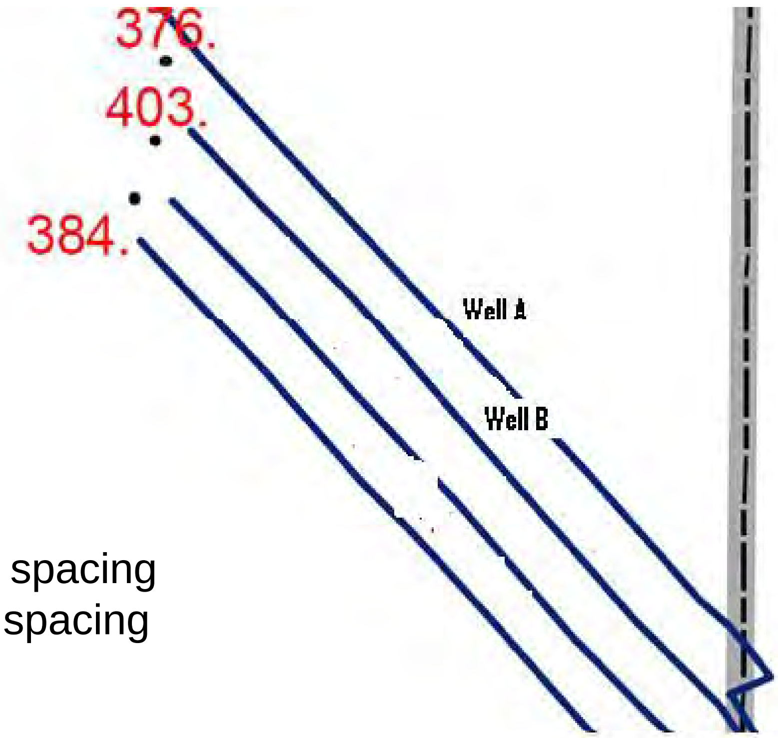
Initial oil production rate, q_i, is sensitive to perforated interval



$$q_i = \exp(3.782191508 + 0.000346087 \times Perforated\ interval + \varepsilon_q)$$

Where $\varepsilon_q \sim N(0, SD = 0.8638)$

We define well spacing as follows:

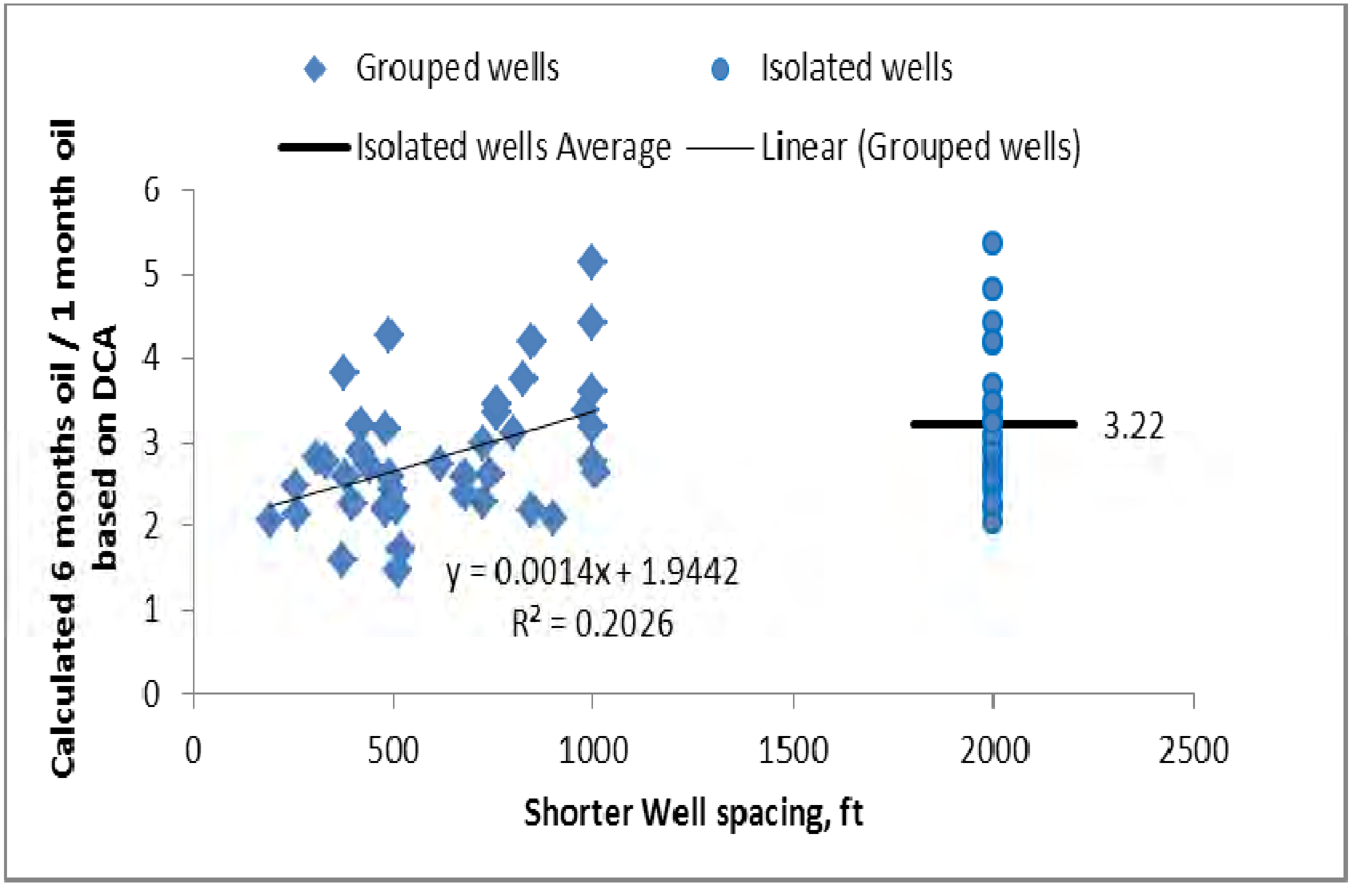


WS1 = shorter well spacing
WS2 = longer well spacing

WS1 of Well B= 376 ft
WS2 of Well B= 403 ft

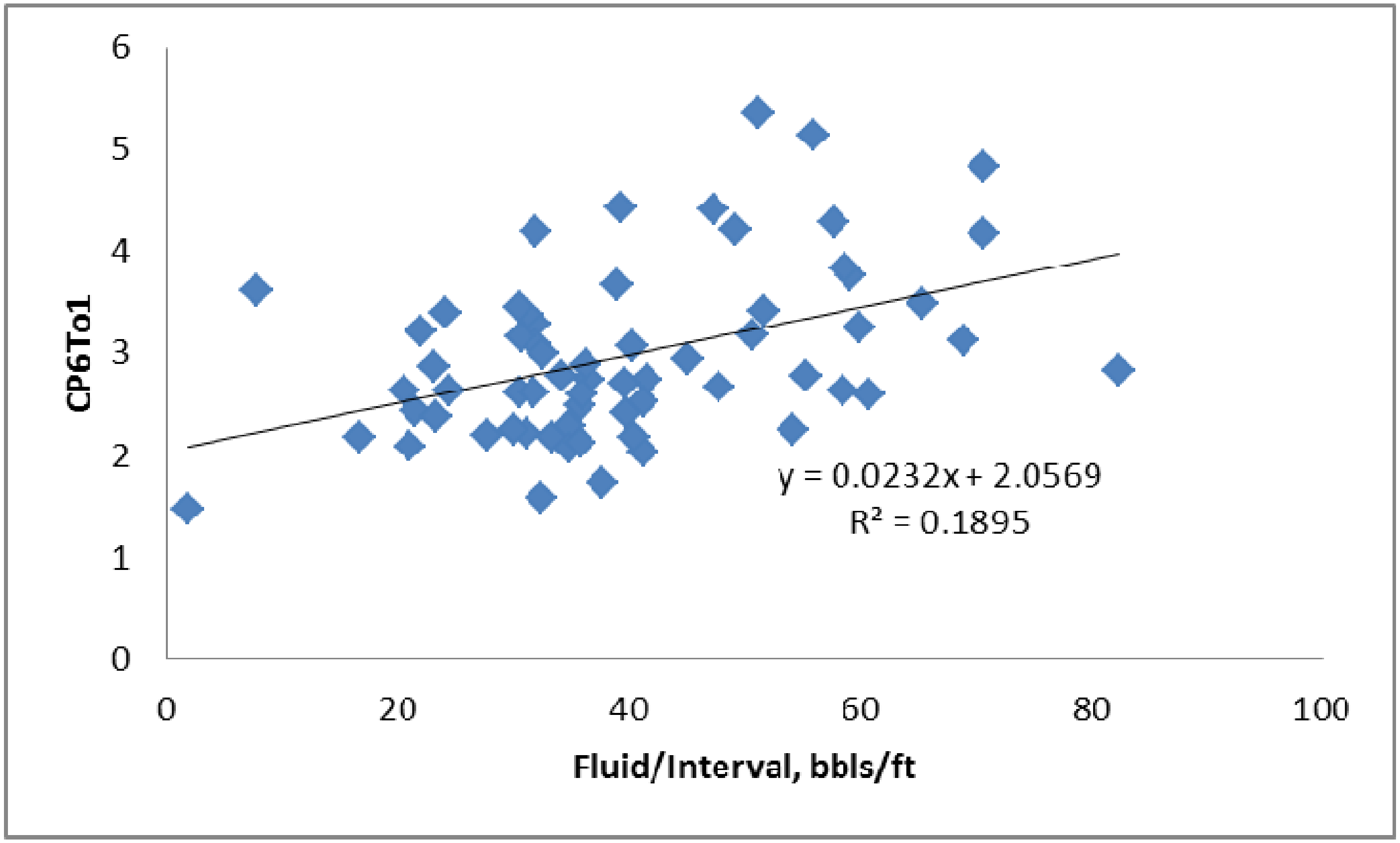
WS1 of Well A= 376 ft
WS2 of Well A= 2000 ft (max)

The ratio of cumulative production at month 6 to cumulative production at month 1 (CP6to1) is sensitive to WS1



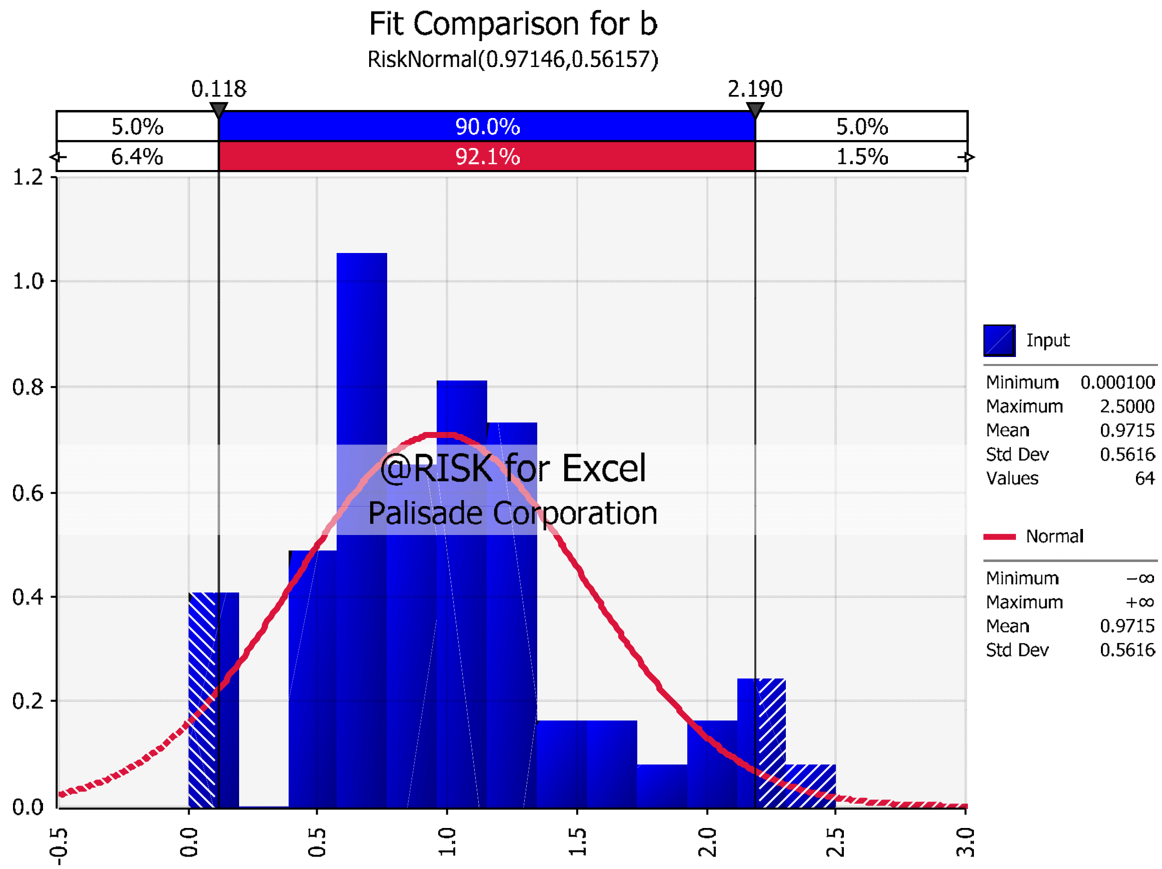
CP6to1 has a positive correlation with WS1

CP6to1 is also sensitive to fluid/perforated interval



CP6to1 has a positive correlation with fluid/interval

The hyperbolic decline curve parameter b was not strongly related to decision parameters

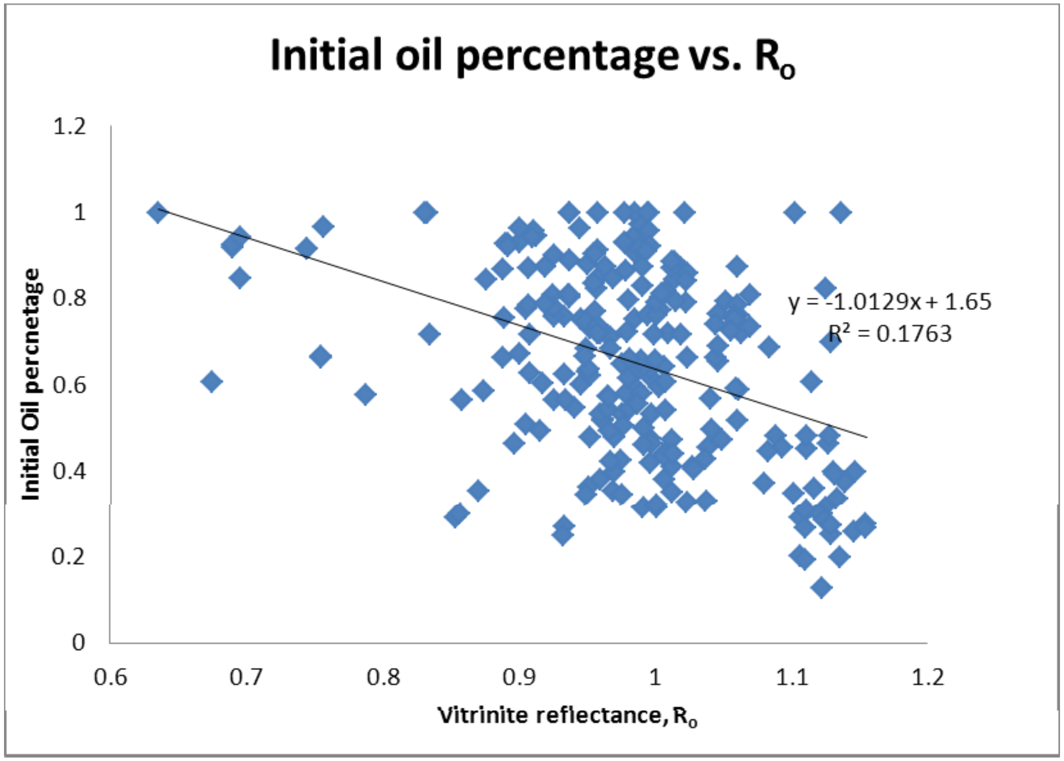


$$b = 0.9715 + \varepsilon_b \text{ Where } \varepsilon_b \sim N(0, SD = 0.5616)$$

We developed a preliminary GOR model to relate gas rate to oil rate and vice versa

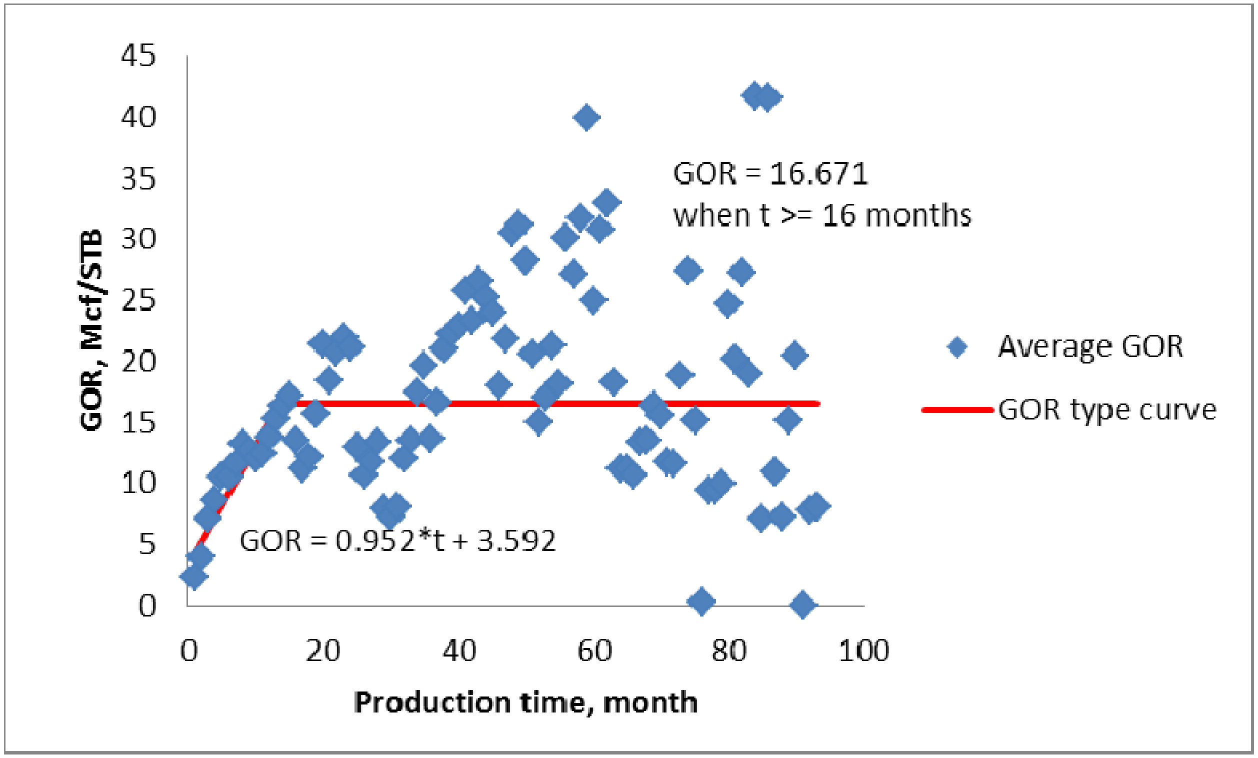
- Correlation of initial GOR to thermal maturity
- Type curve for GOR vs time
- All active horizontal wells in study area used
- 252 wells/leases

Initial oil percentage has a negative relationship with thermal maturity (R_o)



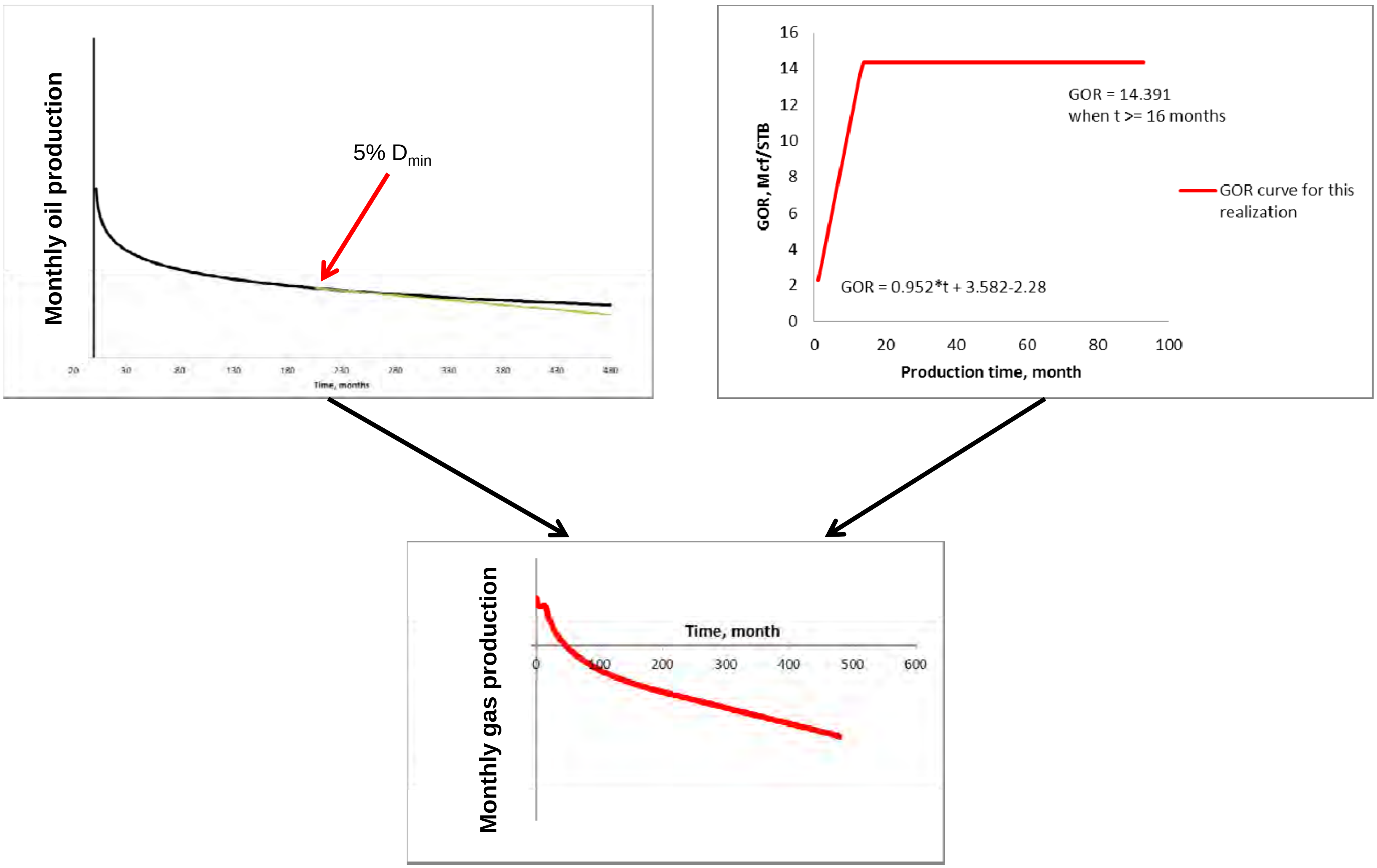
$$Initial\ oil\ Percentage = -1.0129 * R_0 + 1.65 + \varepsilon_o, \text{ where } \varepsilon_o \sim N(0, SD = 0.201064)$$

A deterministic GOR type curve was calculated from well production data normalized to a common start time



We will refine this and add uncertainty in future work

Gas production is calculated from oil production and the GOR type curve

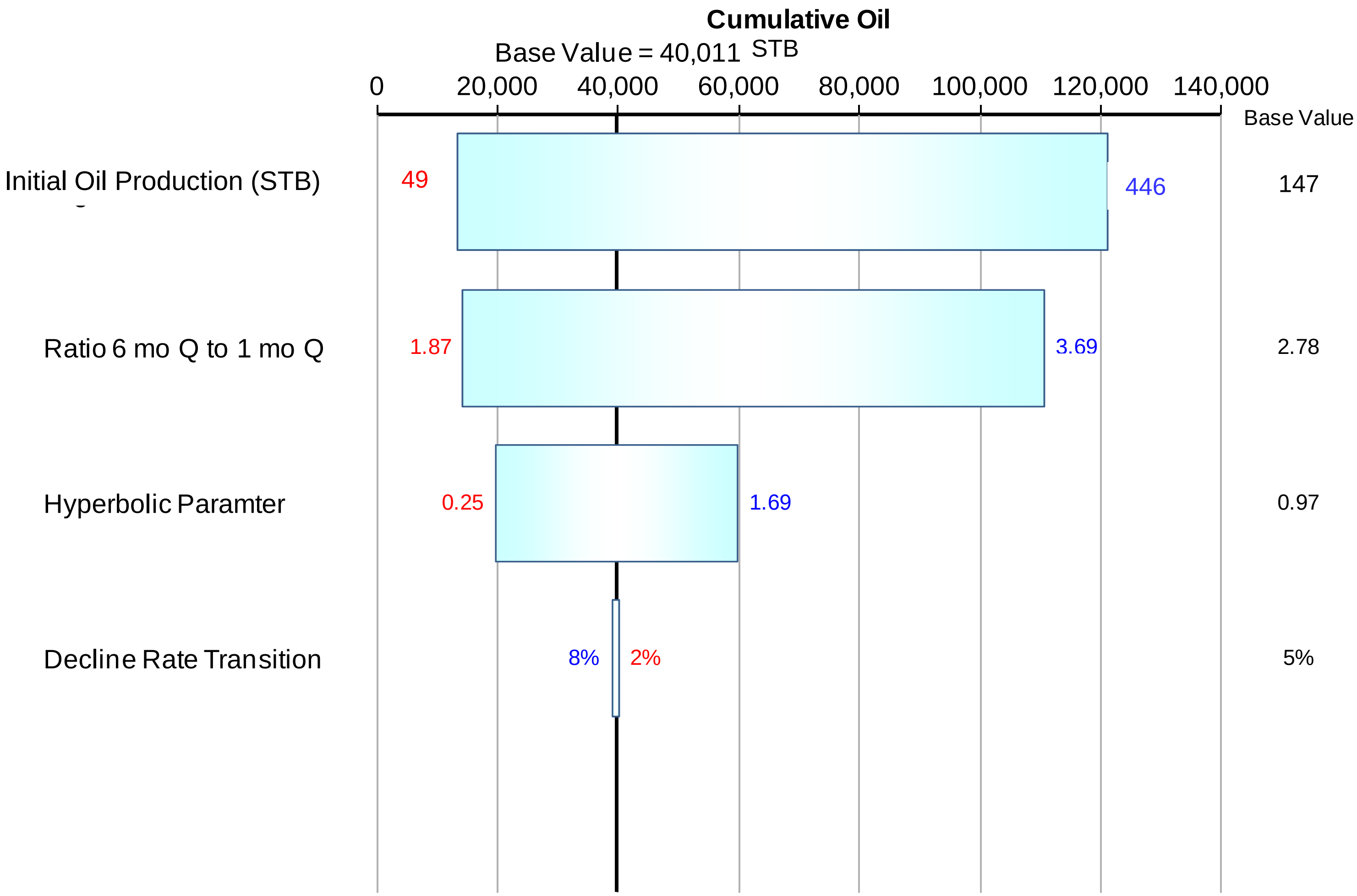


We ran sensitivity analyses and Monte Carlo simulations to investigate and test the models

For these sample calculations, we used the study-area average perforated interval, well spacing, fluid pumped, and thermal maturity

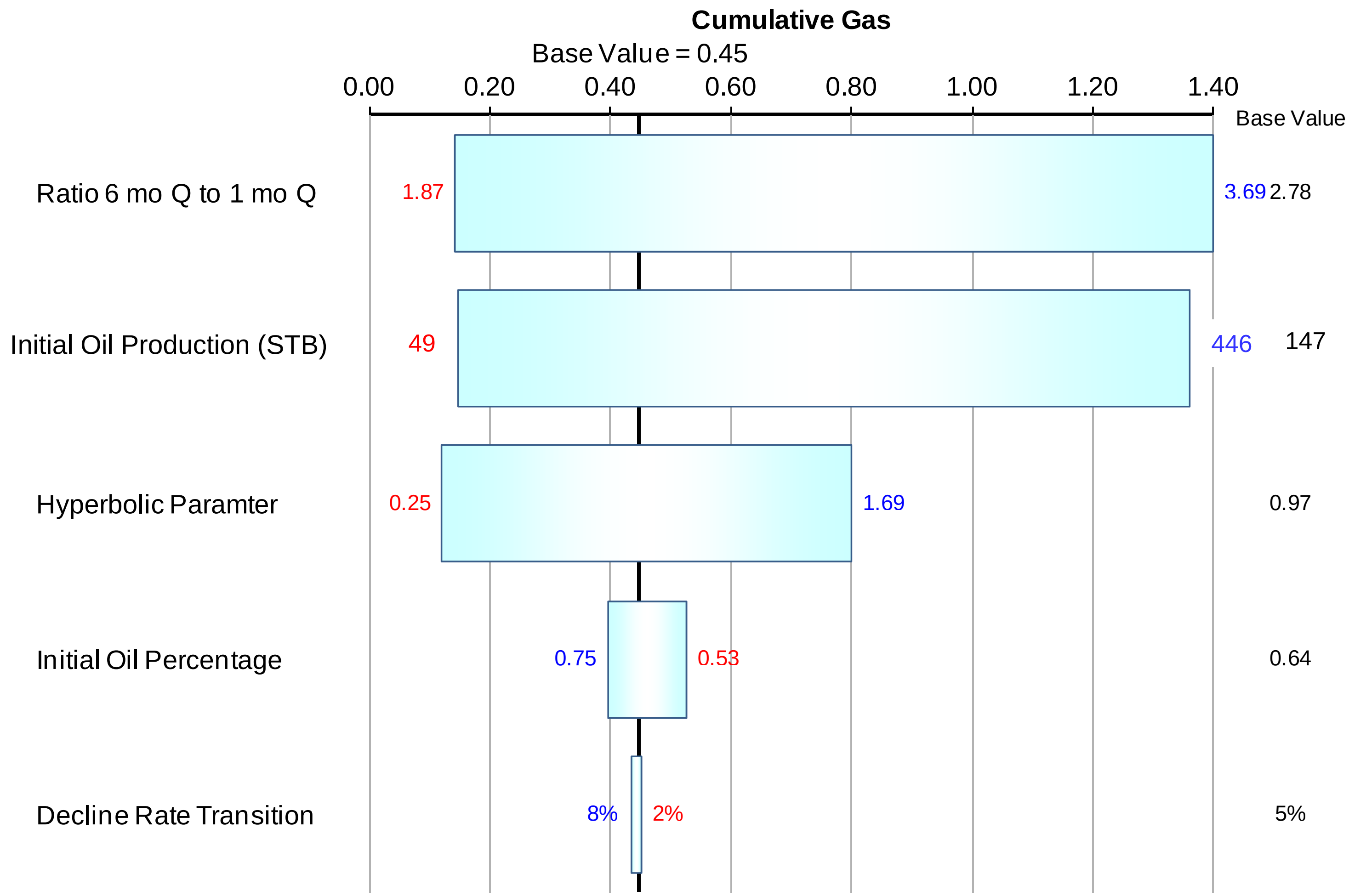
- Perforated interval: 3,500 ft
- Well spacing: 600 ft
- Fluid pumped: 125,000 bbls
- Thermal maturity: 0.93

Not surprisingly, uncertainty in initial production rate dominates our uncertainty in estimated oil recovery



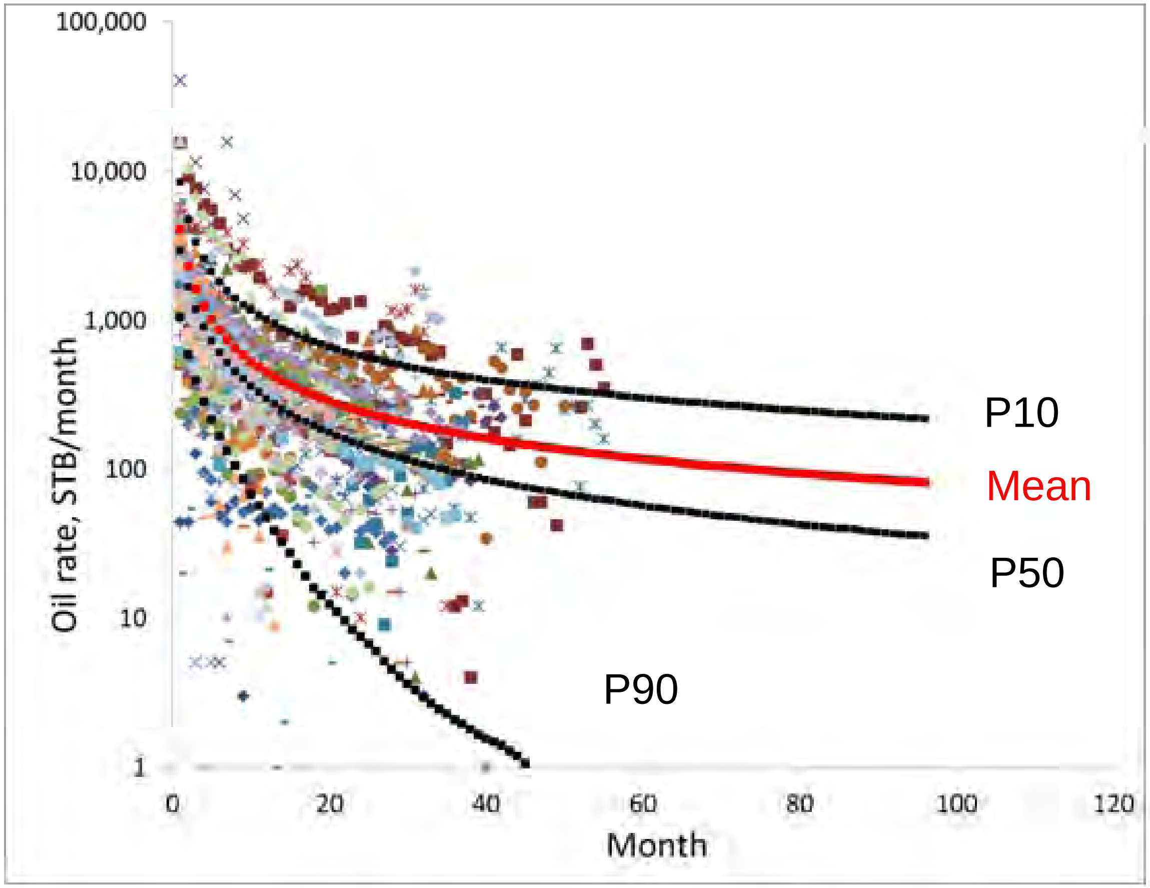
Initial oil production rate and CP6to1 are the two primary influential factors for estimated oil recovery.

Gas production, calculated from oil production and GOR, exhibits similar risk drivers



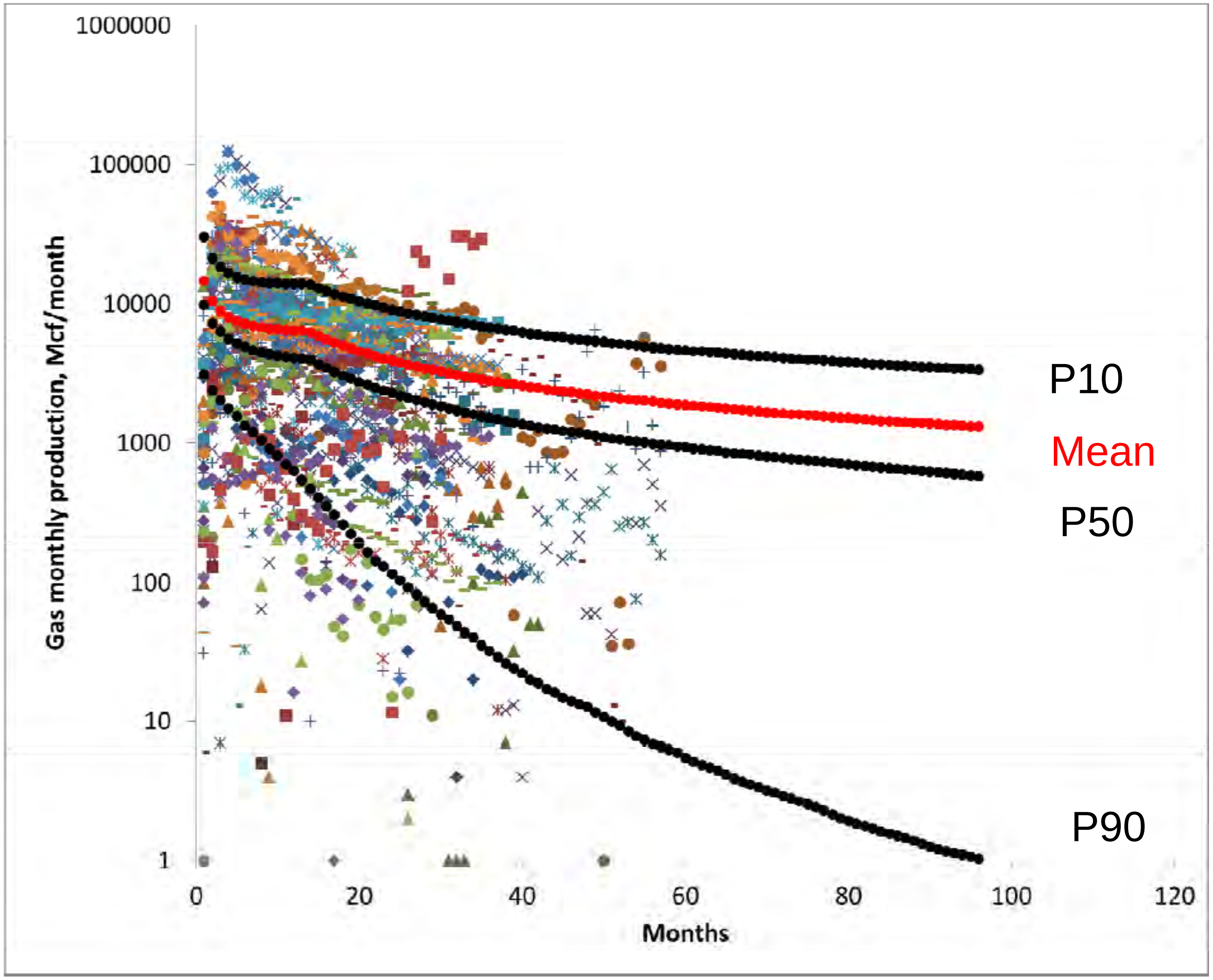
CP6to1 and initial oil production rate are the two primary influential factors for estimated gas recovery.

The probabilistic decline curve model matches the actual distribution of oil production well



Monte Carlo simulation of single well with study-area average completion parameters, 1000 realizations

The probabilistic decline curve model does not match actual gas production quite as well



We are continuing to refine our GOR type curve.

Finally, we relate performance to production decisions (spacing, perforated interval, and fluid volume)

A unit area of 3500 ft x 1000 ft is used to normalize production.

Well Spacing

Well Space (ft)	Cumulative Oil (STB) mean	P10	P50	P90	Cumulative Gas (BCF) mean	P10	P50	P90
1000	62,482	10,961	37,882	135,173	0.79	0.09	0.45	1.81
600	62,958	10,407	38,482	139,968	0.76	0.07	0.40	1.77
200	121,513	17,042	70,424	271,044	1.44	0.10	0.69	3.41

Perforated Interval

Perf Int (ft)	Cumulative Oil (STB) mean	P10	P50	P90	Cumulative Gas (BCF) mean	P10	P50	P90
4500	58,449	9,800	36,634	129,848	0.70	0.07	0.38	1.69
3500	62,958	10,407	38,482	139,968	0.76	0.07	0.40	1.77
2500	80,206	13,541	50,401	184,699	0.99	0.10	0.56	2.37

Fluid Volume

Fluid (lbs)	Cum Oil (STB) mean	P10	P50	P90	Cum Gas (BCF) mean	P10	P50	P90
150,000	70,055	11,996	44,225	159,907	0.85	0.09	0.48	2.04
125,000	62,958	10,407	38,482	139,968	0.76	0.07	0.40	1.77
100,000	55,337	9,456	33,194	119,387	0.67	0.06	0.36	1.46

Summary

- We have demonstrated that gas and oil production decline behavior of northern Barnett shale wells can be correlated to decision variables such as well spacing, perforated interval and stimulation fluid volume.
- The correlations are not high, indicating significant uncertainty in these decisions.
- Modeling these relations and their associated uncertainty should aid in optimization of spacing, completion and stimulation decisions in this area.

Future Plans

- The decline-curve based reservoir model will be updated with more data (>200 wells)
- The GOR model will be refined
- A probabilistic economic model will be incorporated to generate distributions of economic parameters, such as NPV, as functions of decision parameters
- The models will be applied to identify optimal well spacing, completion and stimulation strategies

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Backup

equations for CP6to1 and linear regressions

$$CP6to1 = \frac{\left(1-\left(1+6\frac{D_i}{12}b\right)^{1-\frac{1}{b}}\right)}{\left(1-\left(1+\frac{D_i}{12}b\right)^{1-\frac{1}{b}}\right)}.$$

$$q_i = \exp(3.782191508 + 0.000346087 \times Perforated\ interval + \varepsilon_q)$$

$$\text{Where } \varepsilon_q \sim N(0, SD = 0.8638)$$

For isolated wells (no wells in vicinity, shorter well spacing set to be 2000 ft.)

$$MP6to1 = -0.75656431 + 0.001495744 \times 2000 + 0.022245455 \times \frac{Fluid}{Interval} + \varepsilon_{MP6To1}$$

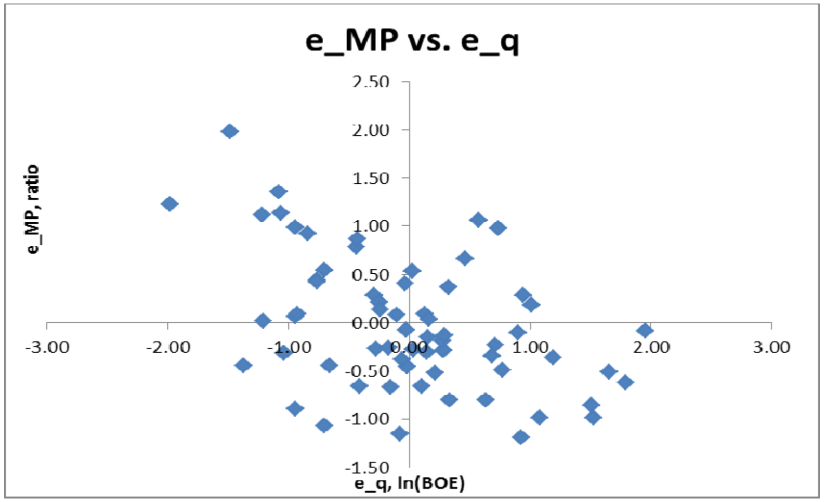
For grouped wells (well spacing read from the directional survey map)

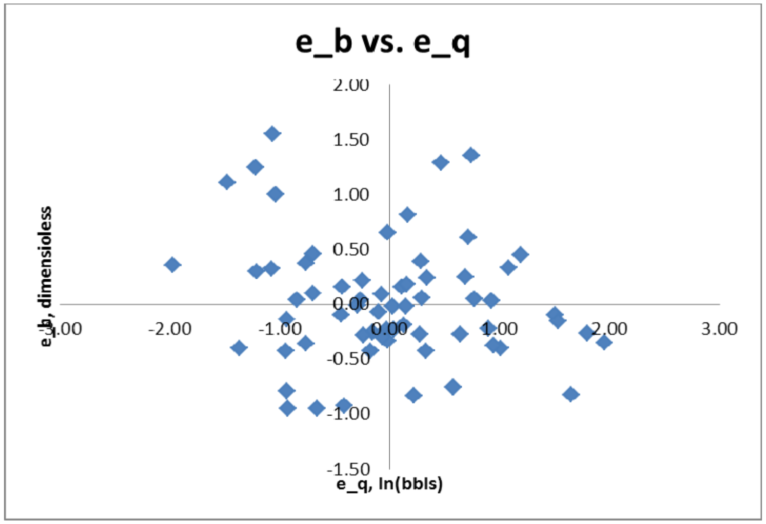
$$MP6to1 = -0.75656431 + 1.843330080 + 0.001495744 \times WS1 + 0.022245455 \times \frac{Fluid}{Interval} + \varepsilon_{MP6to1}$$

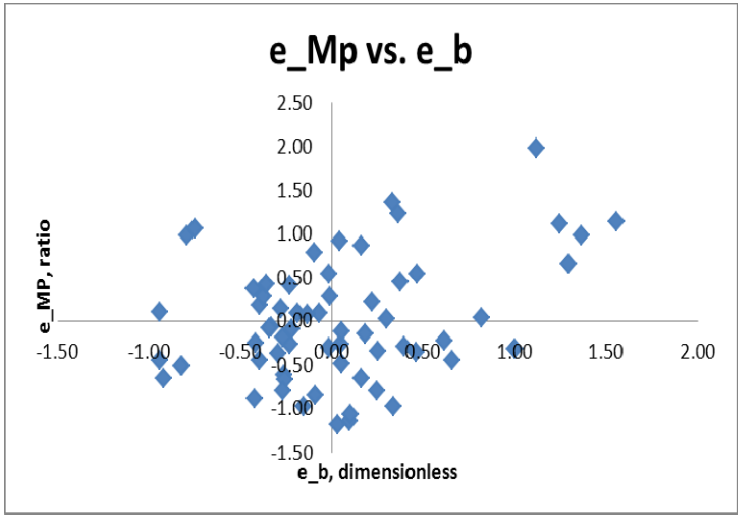
Where, $\varepsilon_{MP6To1} \sim N(0, SD = 0.702472)$

$$b = 0.9715 + \varepsilon_b \text{ Where } \varepsilon_b \sim N(0, SD = 0.5616)$$

Joint distribution of residuals from linear regressions







A joint normal distribution is used to model the residuals

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Joint distribution of residuals from linear regressions

Residuals	Correlations
ε_q, ε_{MP}	-0.4537
ε_q, ε_b	-0.1725
ε_{MP}, ε_b	0.3505

$$\begin{bmatrix} \varepsilon_q \\ \varepsilon_{MP} \\ \varepsilon_b \end{bmatrix} \sim N\left(0, \begin{bmatrix} 0.74618 & -0.27053 & -0.08429 \\ -0.27053 & 0.5073 & 0.13709 \\ -0.08429 & 0.13709 & 0.31539 \end{bmatrix}\right)$$

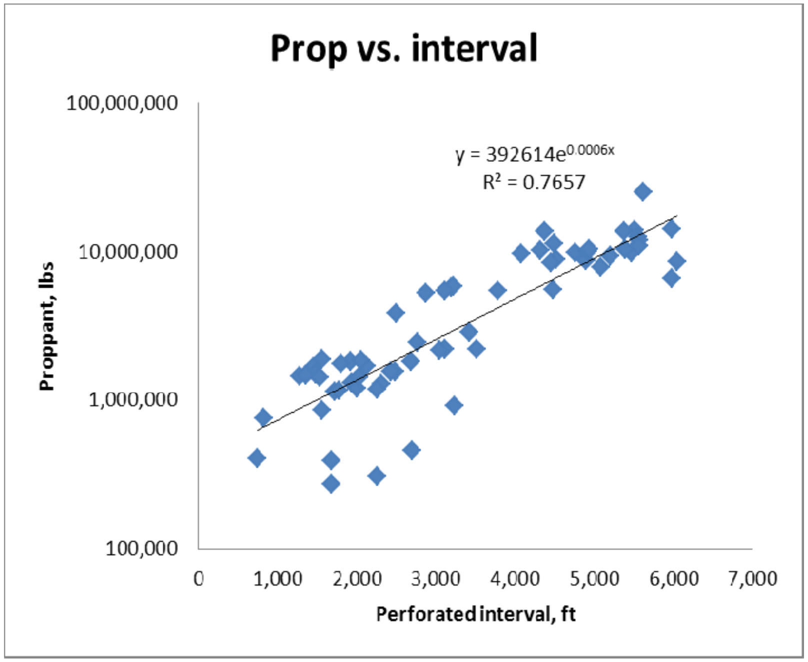
Summary of correlation coefficients

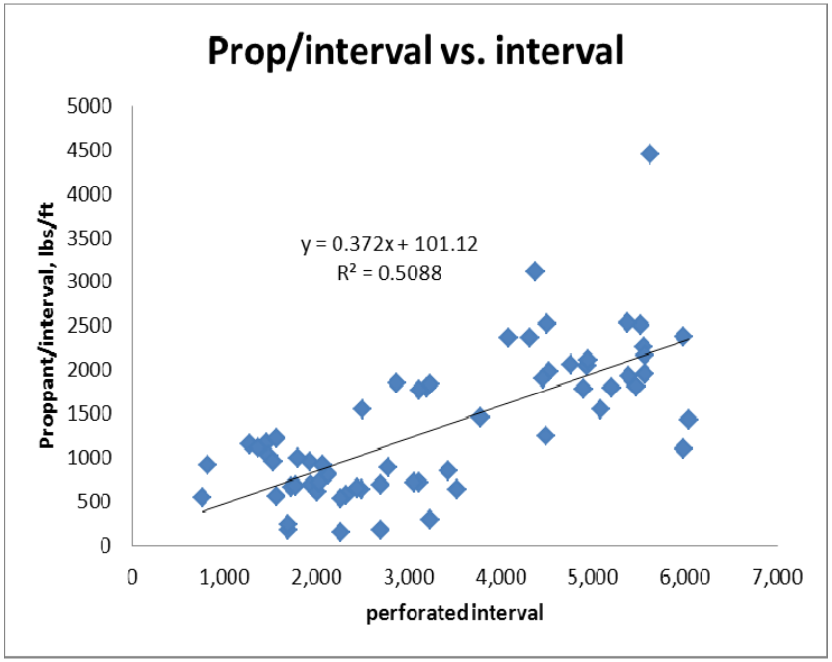
	Fluid	Prop	Stages	Interval	WS1	WS2	Ro	Thick	Depth	Fluid_Interval	Prop_Interval
Oil_log(qi)	0.04	0.20	0.05	0.29	0.11	0.17	0.03	0.06	0.01	0.13	0.14
Oil_Di	0.00	0.03	0.03	0.03	0.07	0.08	0.07	0.00	0.01	0.14	0.03
Oil_b	0.02	0.02	0.00	0.01	0.03	0.00	0.03	0.00	0.02	0.02	0.01
Oil_CP6to1	0.01	0.21	0.06	0.18	0.20	0.13	0.00	0.01	0.00	0.19	0.18
Eq_log(qi)	0.11	0.25	0.08	0.36	0.13	0.22	0.00	0.03	0.02	0.11	0.18
Eq_Di	0.03	0.01	0.00	0.02	0.04	0.01	0.00	0.07	0.15	0.01	0.00
Eq_b	0.02	0.04	0.00	0.03	0.00	0.01	0.02	0.14	0.08	0.00	0.02
Eq_CP6to1	0.01	0.03	0.02	0.02	0.10	0.04	0.00	0.00	0.02	0.06	0.03

This table shows the correlation between geological and completion parameters and decline curve parameters. Black number means positive, red number means negative, yellow shadowed cells are selected relationship.

Oil production is chosen because there is a stronger relationship between CP6to1 and WS1.

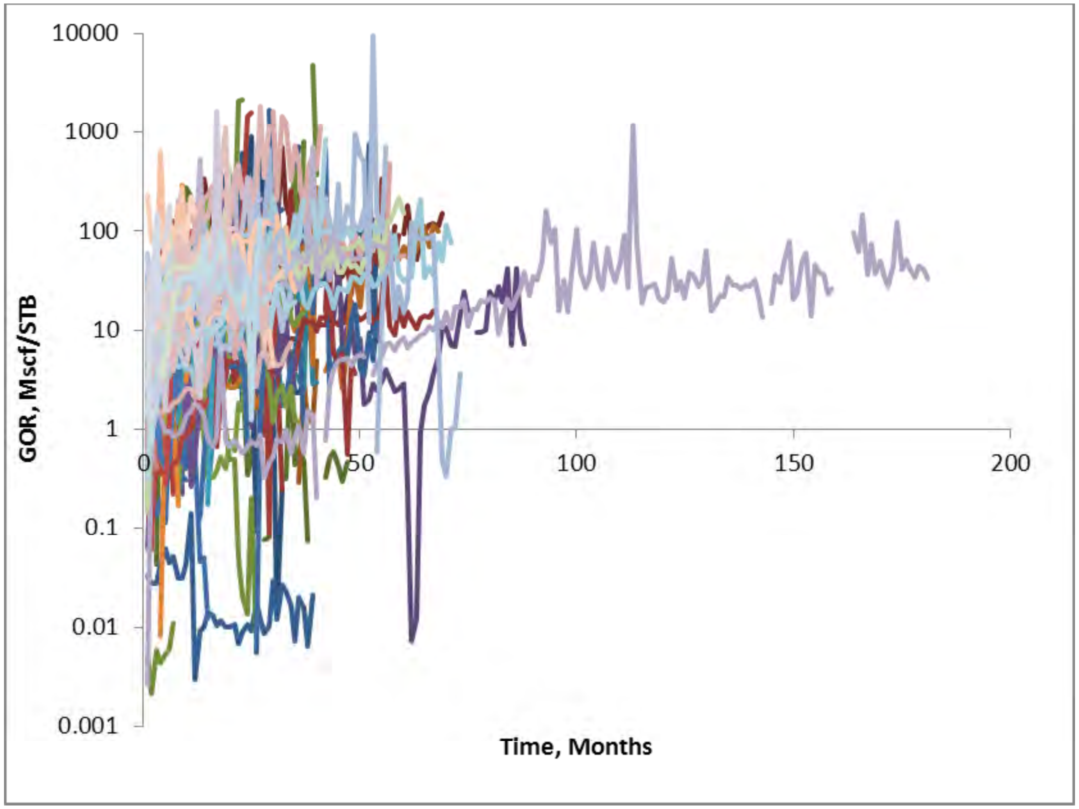
Proppant and perforated interval are highly exponentially correlated





Proppant and perforated interval are highly exponentially related, as a result, prop/interval is highly linearly related to perforated interval. In our model, we assume this exponential relationship is valid for every perforated interval.

GOR increases with time



GOR increases with time. 252 horizontal wells in northern Barnett are plotted.

Impact of decision parameters on oil and gas production

Single Well

Perf Int (ft)	Cum Oil (STB) mean	P10	P50	P90	Cum Gas (BCF) mean	P10	P50	P90
4500	47,045	7,406	29,065	101,672	0.57	0.05	0.32	1.36
3500	35,529	7,016	23,257	76,660	0.43	0.05	0.25	0.98
2500	37,296	6,244	22,561	81,406	0.47	0.05	0.25	1.07

Well Space (ft)	Cum Oil (STB) mean	P10	P50	P90	Cum Gas (BCF) mean	P10	P50	P90
1000	61,298	12,367	41,701	129,167	0.77	0.10	0.48	1.74
600	35,529	7,016	23,257	76,660	0.43	0.05	0.25	0.98
200	26,237	3,568	15,051	57,455	0.32	0.02	0.16	0.72

Fluid (lbs)	Cum Oil (STB) mean	P10	P50	P90	Cum Gas (BCF) mean	P10	P50	P90
150,000	44,233	7,697	27,907	96,458	0.55	0.06	0.31	1.23
125,000	35,529	7,016	23,257	76,660	0.43	0.05	0.25	0.98
100,000	33,173	6,262	20,530	72,286	0.41	0.04	0.22	0.97

When comparing different values of one parameter (e.g., perforated interval), the base value of other two parameters are used (well spacing = 600, fluid pumped = 125,000 bbls).