Optimizing Completion Design & Well Spacing Through Production Analysis and Reservoir Characterization

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Schubarth Inc.

What Do We Optimize

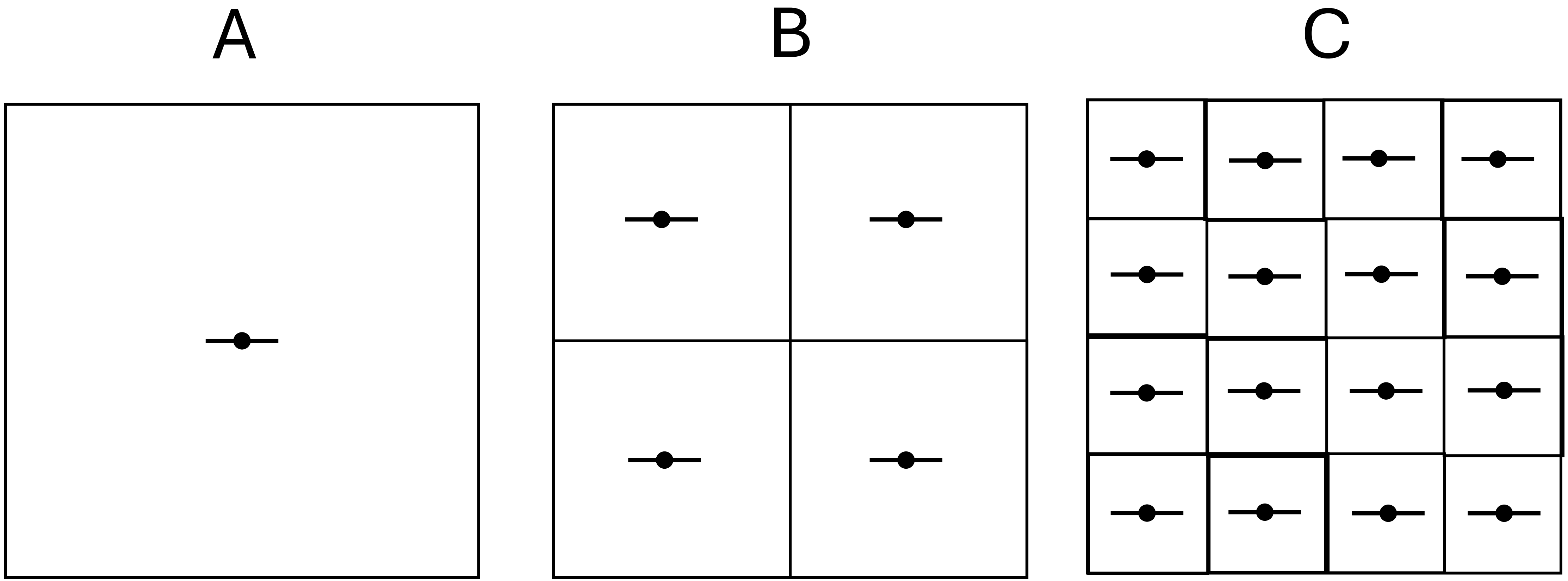
- Perf Efficiency?
- Cycle Time?
- 90 Day Cumulative Recovery?
- Reducing Total Well Cost?
- Other?

- **ECONOMICS**
  - **NPV** - (Net Present Value)
  - **ROI** - (Return on Investment)
  - **ROR** – (Rate of Return)
  - **Time to Payout**
  - **Others?**

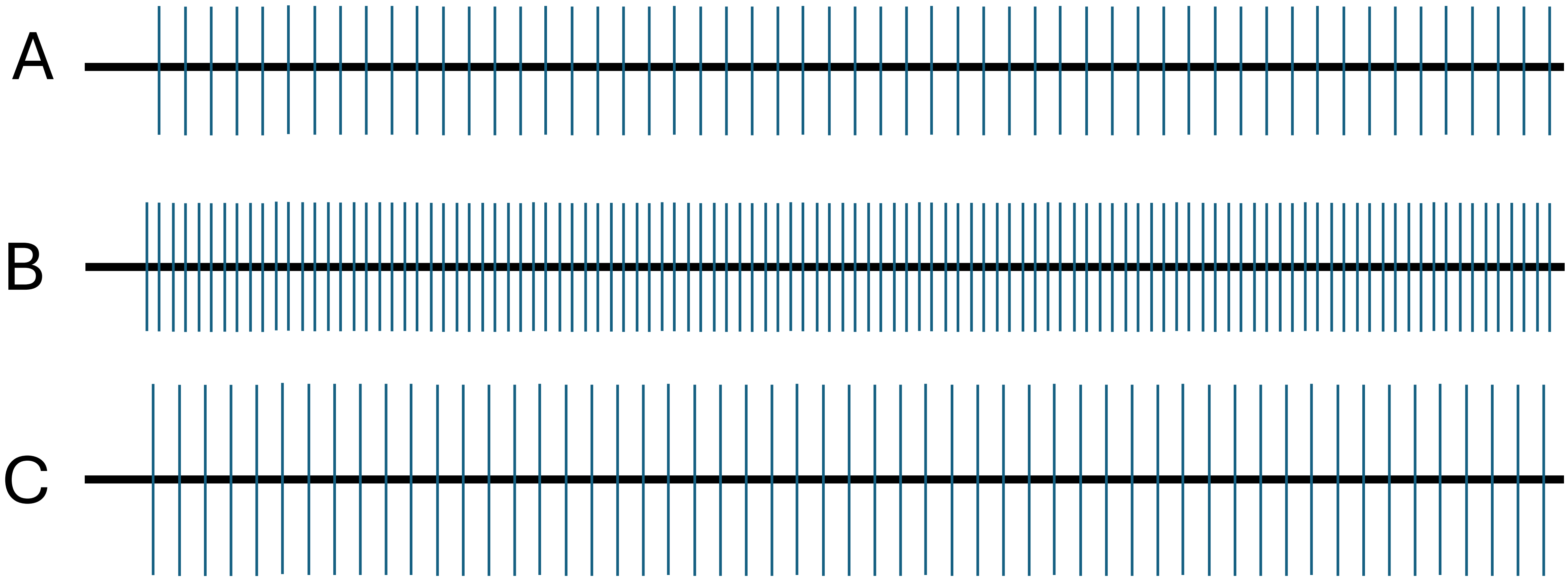
Economics

- Requires:
  - An understanding of future cash flow
  - An understanding of completion design on future cash flow
  - An understanding of completion design on capital cost
  - An understanding of completion design on drainage area
  - An understanding of well spacing on well EUR

How would you develop this reservoir?



Which well will produce the most?



A simple map view of the completion design

The producing fractures are transverse to the wellbore and cover the vertical extent of the net pay

These fractures are the conduits for flow to deplete the reservoir between the fractures

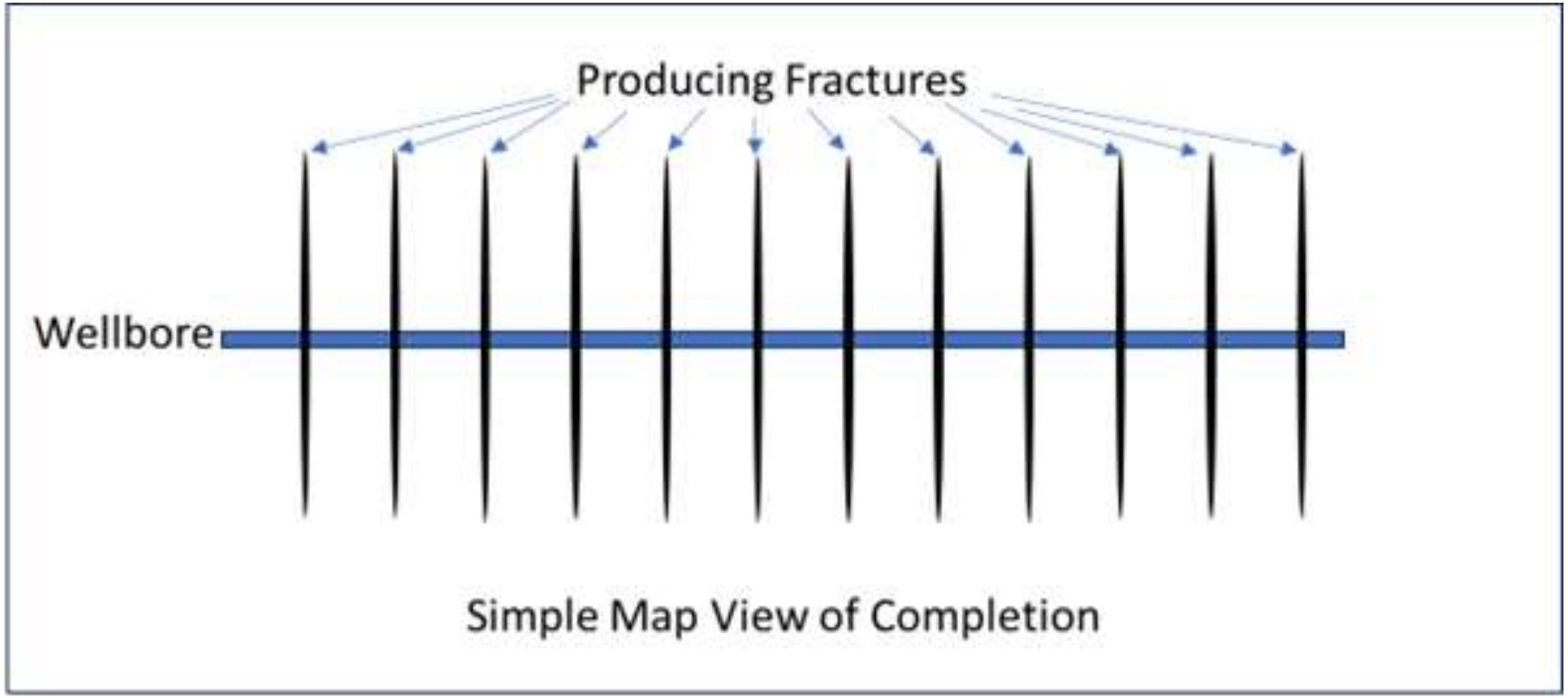


Figure 1 – Map view of completion

Completion Design

- Key Parameters
  - Stage Length
  - Entry hole design
    - Hole size
    - Number of holes per cluster
    - Number of clusters per stage
  - Pump Rate
  - Fluid Choice
  - Proppant Choice
  - Zonal Isolation between stages

First is Understanding what we can Control and cannot Control in our Completion Design

What we can control

- Lateral length
- Treatment parameters
  - Proppant - volume & type
  - Fluids - volume & type
  - Perforations - number & location
  - Pump Rate
- Number of stages pumped
  - Stage spacing

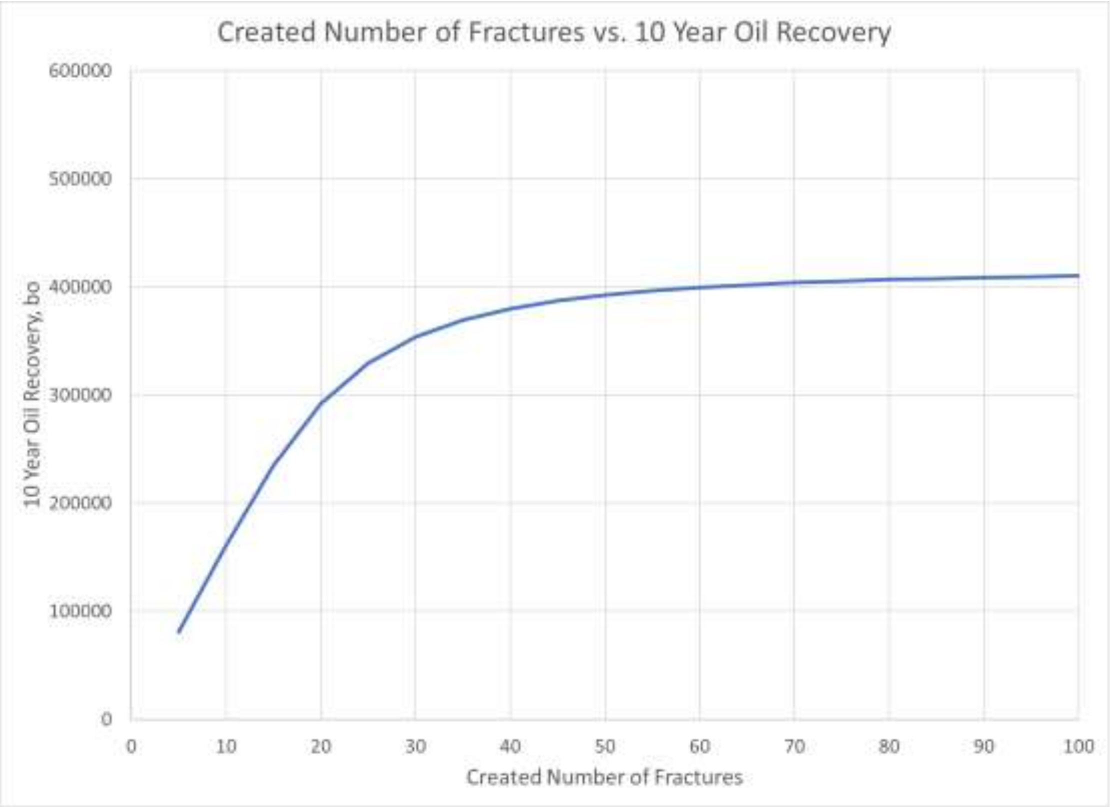
What we cannot control

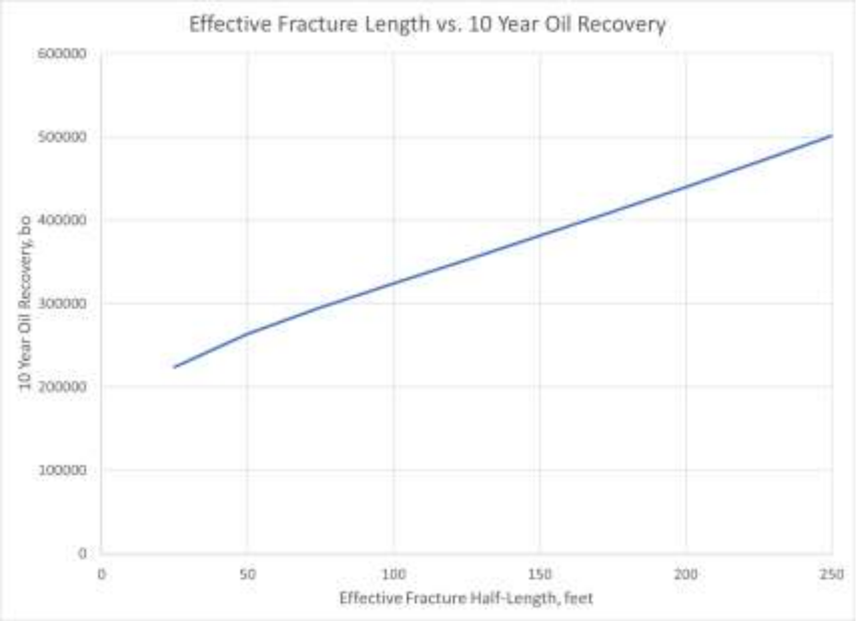
- Formation properties
  - Permeability
  - Porosity*
  - Water Saturation*
  - Net Pay*
- Reservoir fluid properties*
- In-situ Stresses

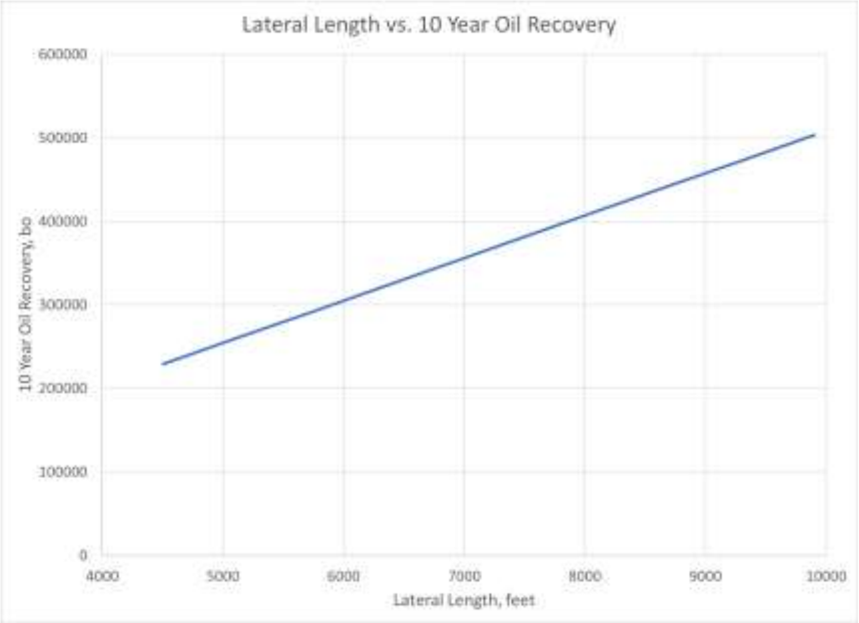
* Determines Hydrocarbons in place per acre

Of the Things We Can Control

- **Increasing lateral length & effective fracture half length (L_f) proportionally increase recovery**
- **But increasing number of fractures has a diminishing impact on recovery**







Production as a Diagnostic Tool

- Examine the typical production decline shape of Unconventional Hz Wells
- Why do they decline this way?
- What can we learn?
- How can we use this information?
- Optimizing completion & well spacing design
- Economic & Environmental impact

Rate Normalization

- Normalized rate:
  - $Qn = \frac{Q}{(Pi - Pwf)} * (\mathrm{Pi} - \mathrm{Pn})$ …….*for Oil*
  - $Qn = \frac{Q}{(Pi^2 - Pwf^2)} * (\mathrm{Pi}^2 - \mathrm{Pn}^2)$ …….*for Gas*

  - Where:
    - Qn = Normalized Rate
    - Q = Actual Rate
    - Pi = Initial Pressure
    - Pwf = Flowing pressure
    - Pn = Normalized flowing pressure (the flowing pressure the model will be produced at)

Time Normalization

- Normalized time:
  - $\Delta tn = \frac{Q}{Qn} \Delta \mathrm{t}$
  - Where:
    - $\Delta tn =$ Normalized incremental time
    - Q = Actual Rate
    - Qn = Normalized rate

- **Early time linear flow**
  - **f($k^{1/2}$ and effective frac surface area)**
- **Transitional flow**
  - **f(k and distance between fracs)**
- **Late time linear flow**
  - **f($k^{1/2}$ & Lateral Length)**

Table 1 - Possible Production Match For Figure 2 Well

Fracs/Stage	Producing Fracs	Perm, nD	A*SQRT(k)	ETLF/LTLF Multiple
2	44	4500	90,888	2.1
3	66	2000	90,888	3.2
4	88	1125	90,888	4.3
5	110	720	90,888	5.4
6	132	500	90,888	6.4
7	154	367	90,888	7.5
8	176	281	90,888	8.6

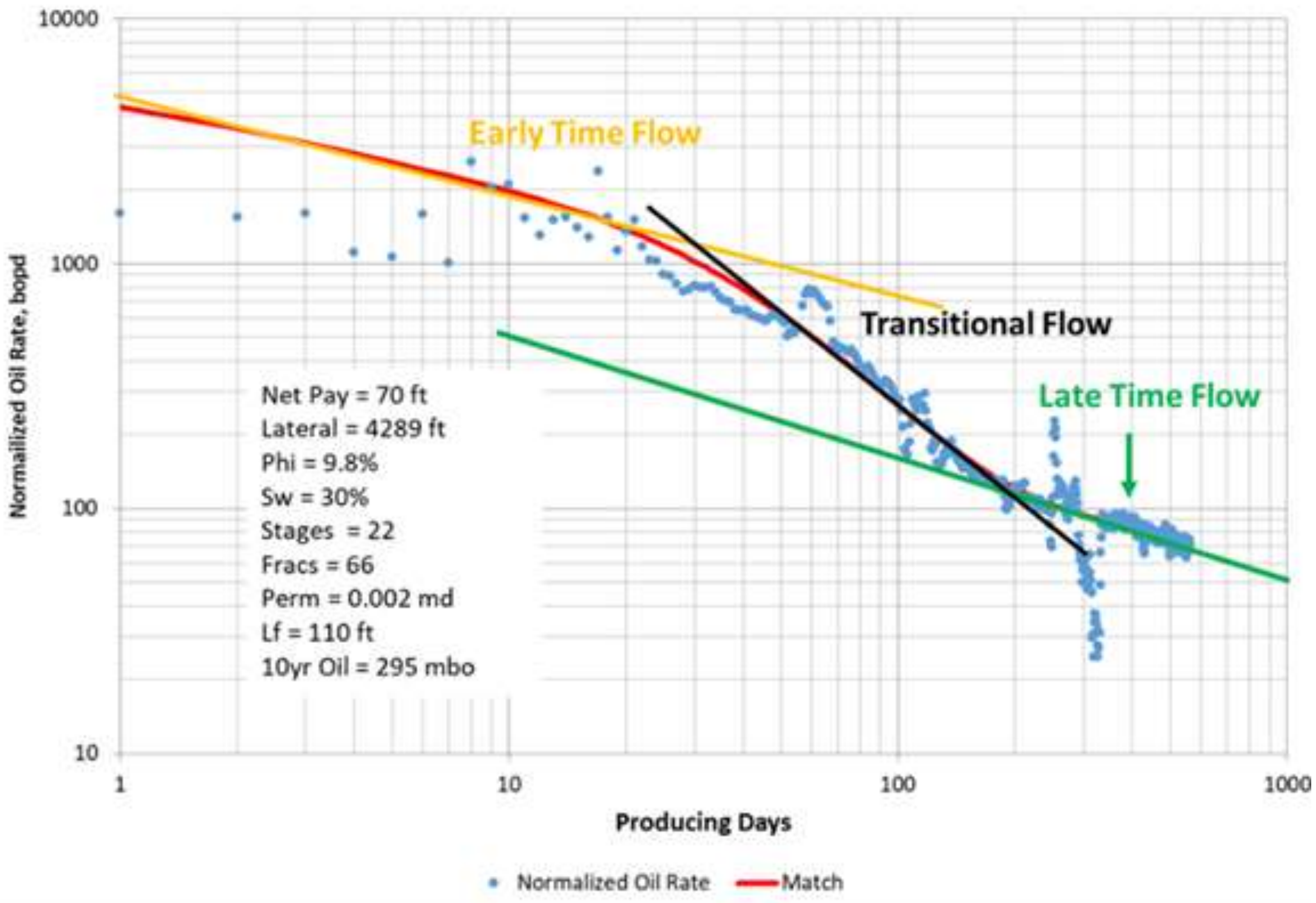


Figure 2 – Example Unconventional Multi-Stage Producing Well

- The graph indicates matched effective fracture half-lengths vs. sand pumped per producing frac
- There is a good correlation indicated in the data
- There is a diminishing return for increased L_f with increasing sand

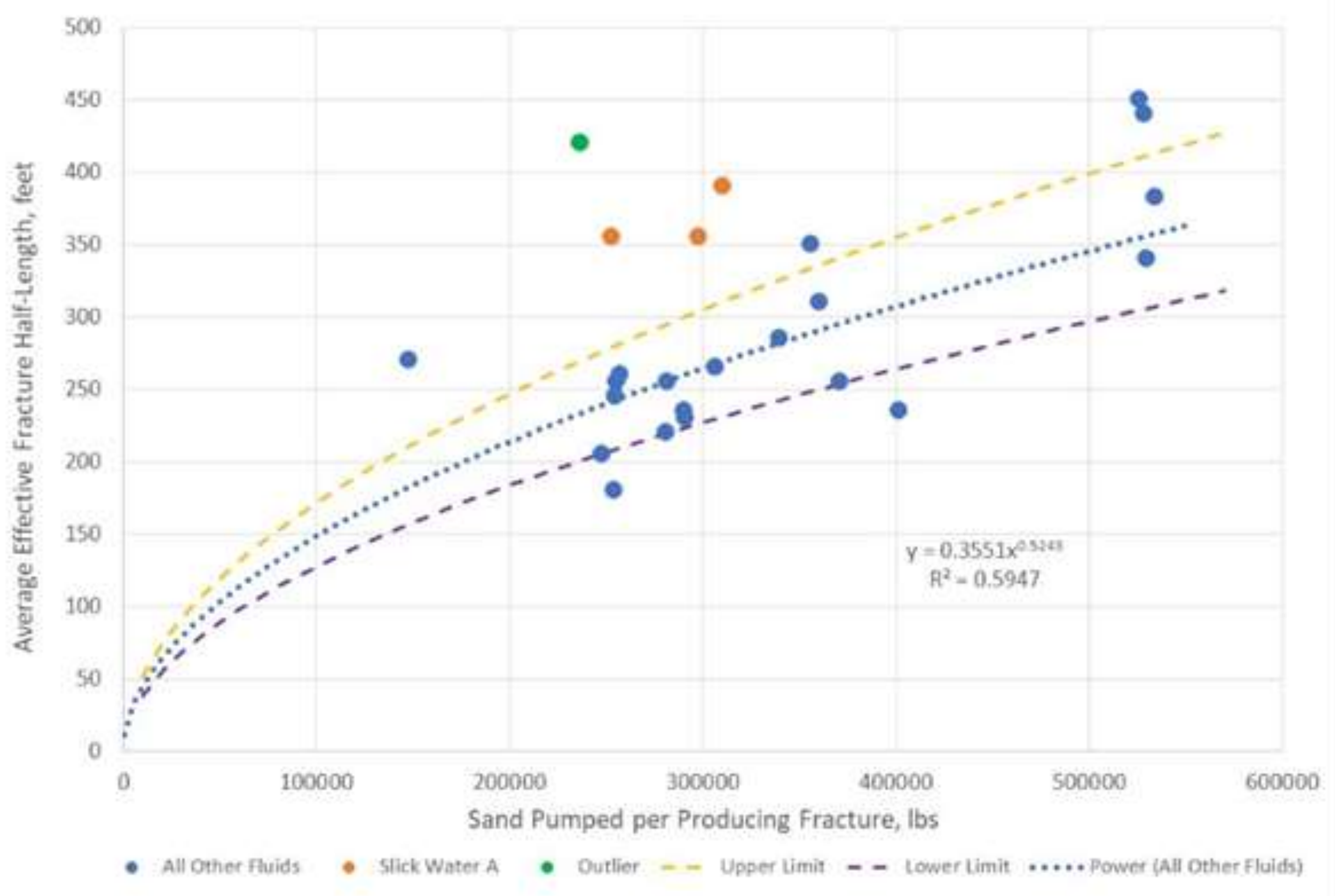
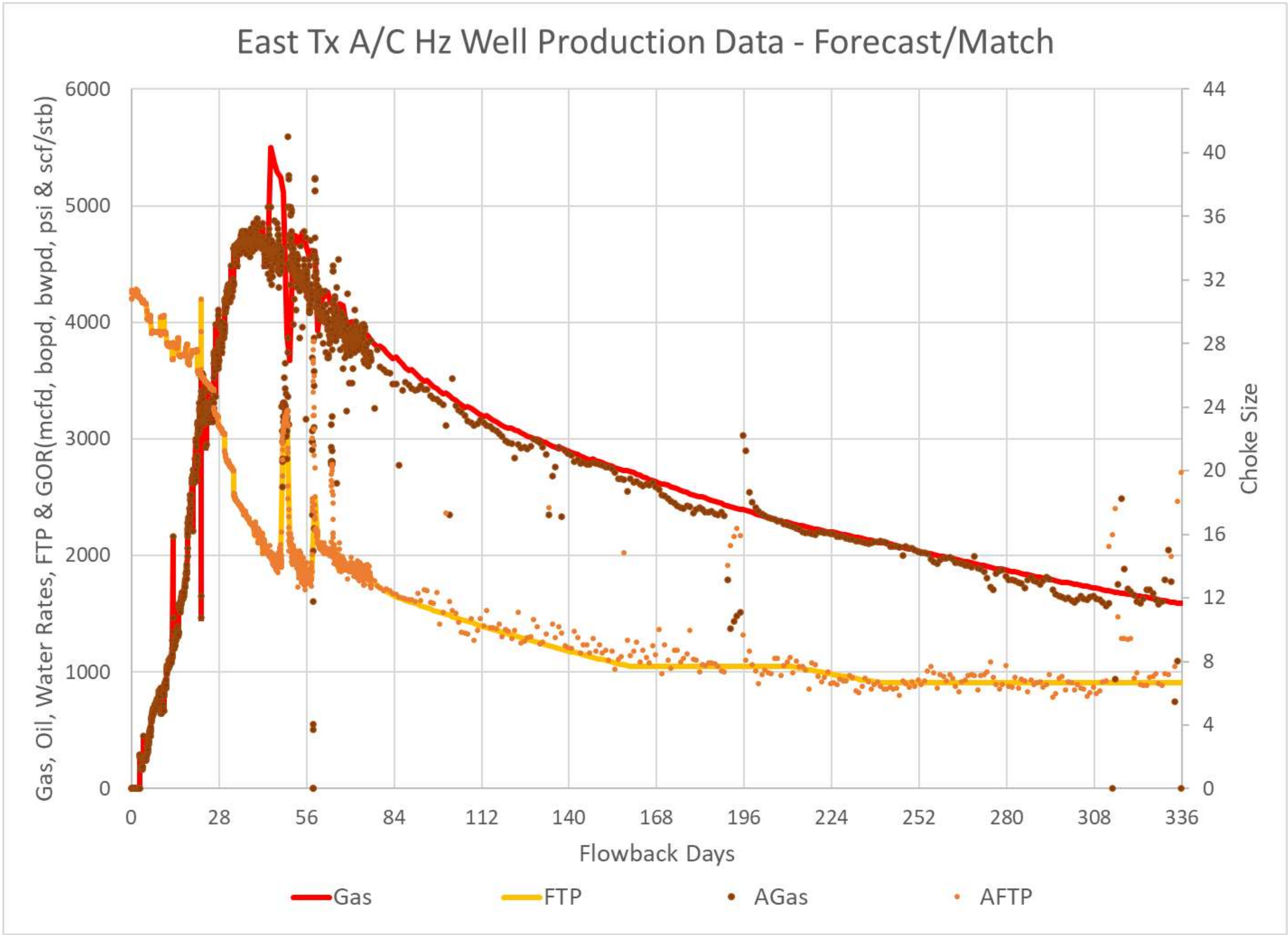


Figure 8 - Example of Treatment Volumes Versus Effective Fracture Half-Length

Table 2 - The Effect of Increased Perf Efficiency

Fracs/Stage	End of ETLF Days	Sand/Frac lbs	Eff Lf feet	A*SQRT(k)
1	1828	500,000	345	38,138
2	457	250,000	240	53,035
3	203	166,667	194	64,317
4	114	125,000	167	73,750
5	73	100,000	149	82,009



East Tx A/C Hz Well Production Data - Forecast/Match
Gas, Oil, Water Rates, FTP & GOR(mcfd, bopd, bwpd, psi & scf/stb)
Choke Size
Flowback Days
0
1000
2000
3000
4000
5000
6000
0
4
8
12
16
20
24
28
32
36
40
44
0
28
56
84
112
140
168
196
224
252
280
308
336
Gas
FTP
AGas
AFTP

- Production history matching allows us to characterize the reservoir permeability
- SPE 28610 – permeability distribution of the Frontier Sand on the Moxa Arch, Wyoming
  - Widely distributed perm
- Unconventional Reservoirs:
  - Much less variation in permeability from well to well
  - Very quiet depositional environment leads to consistent lateral deposition despite vertical heterogeneity

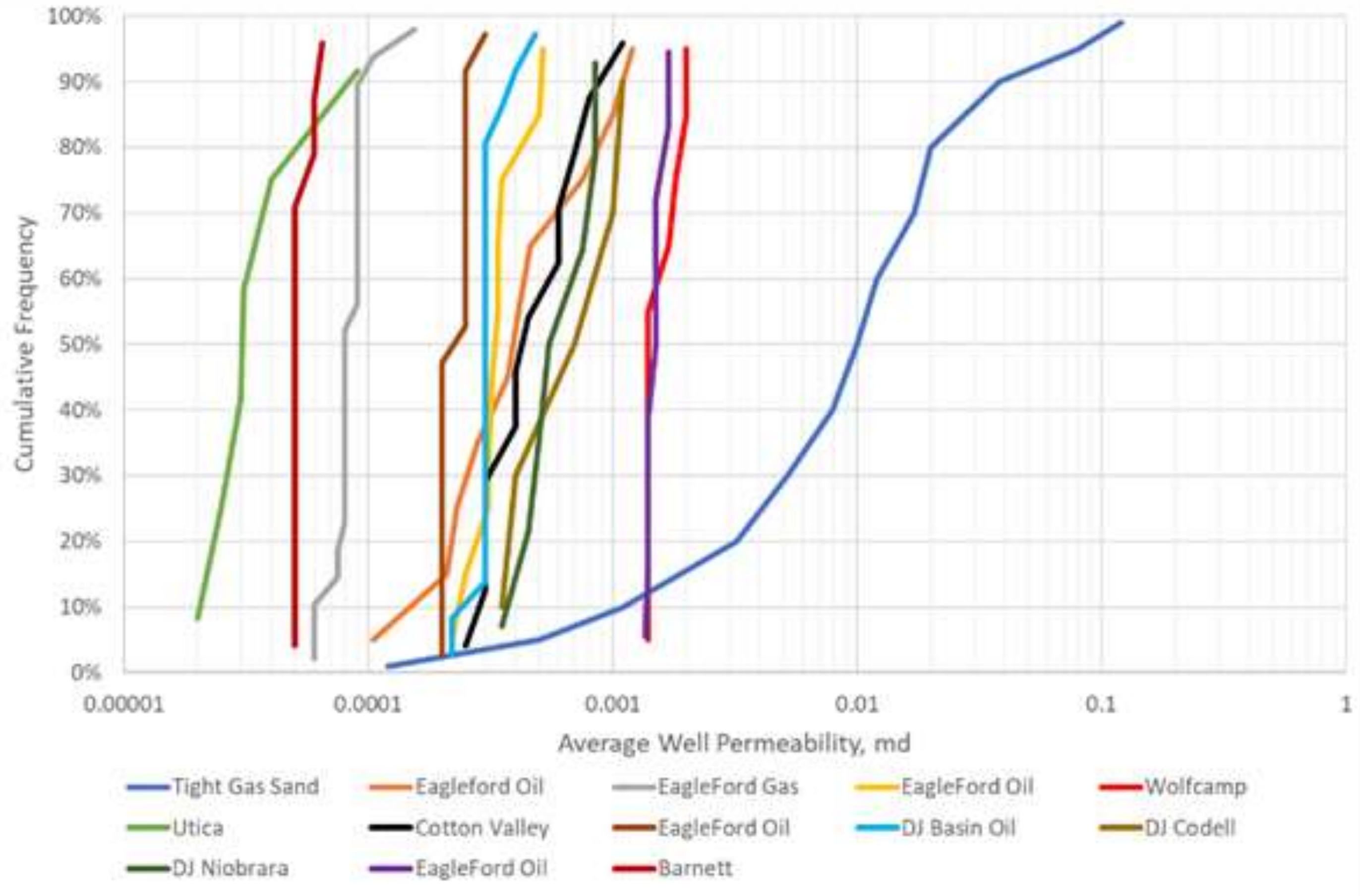
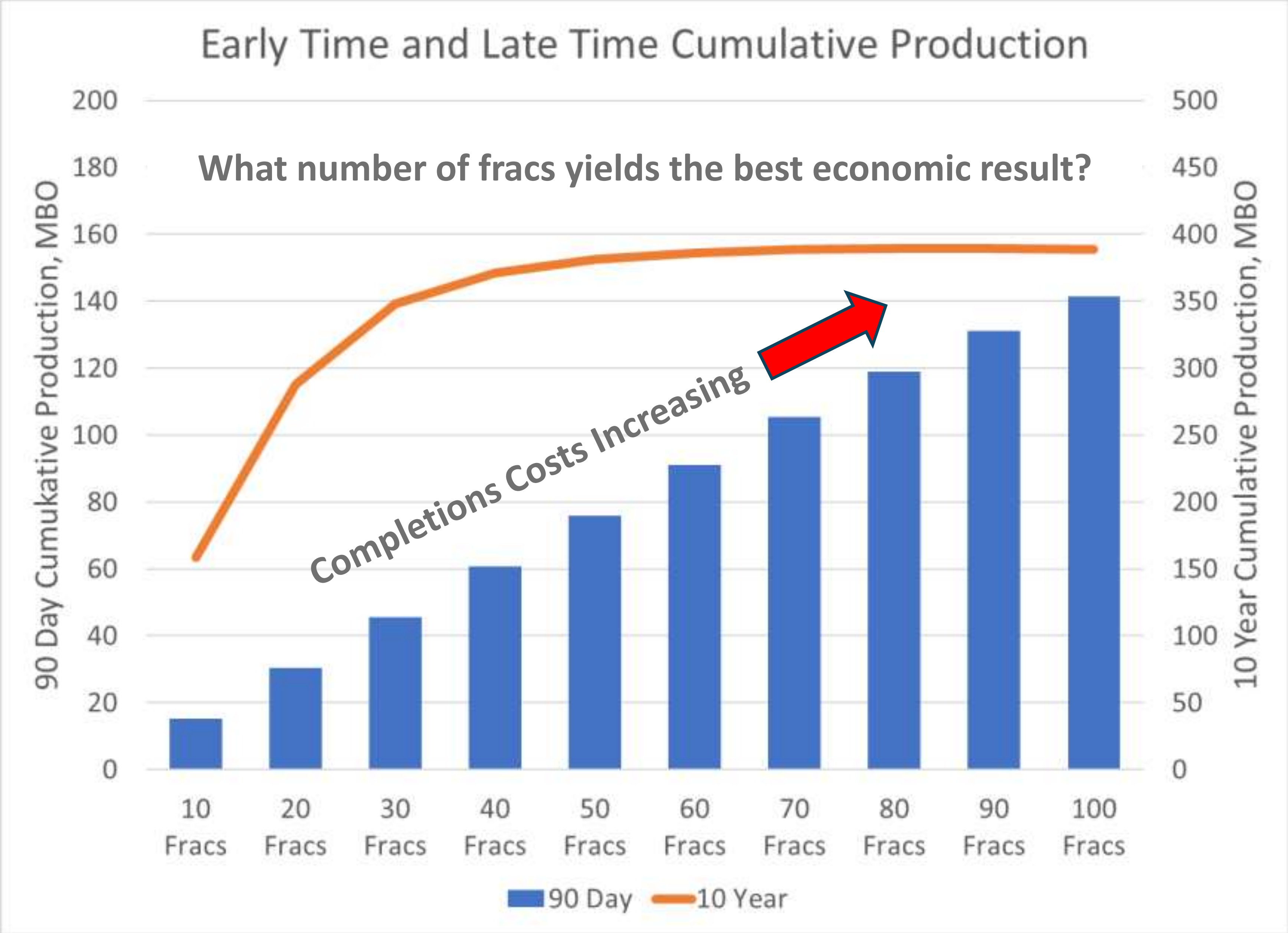


Figure 6 - Distribution of Average Permeability in Various US Reservoirs



Early Time and Late Time Cumulative Production
What number of fracs yields the best economic result?
Completions Costs Increasing
90 Day Cumukative Production, MBO
10 Year Cumulative Production, MBO
200
180
160
140
120
100
80
60
40
20
0
500
450
400
350
300
250
200
150
100
50
0
10 Fracs
20 Fracs
30 Fracs
40 Fracs
50 Fracs
60 Fracs
70 Fracs
80 Fracs
90 Fracs
100 Fracs
90 Day
10 Year

Completion Optimization

- SPE 201716
- Current completion design – Red dot
  - 57 stages
  - 523 klbs sand/stage
- Improved completion design – Yellow dot
  - 42 stages
  - 722 klbs sand/stage
- Completion design change results:
  - Reduced well cost by $700k (9%)
  - Increased EUR/well by >35%
  - Reduced Completion cost/bo by >45%

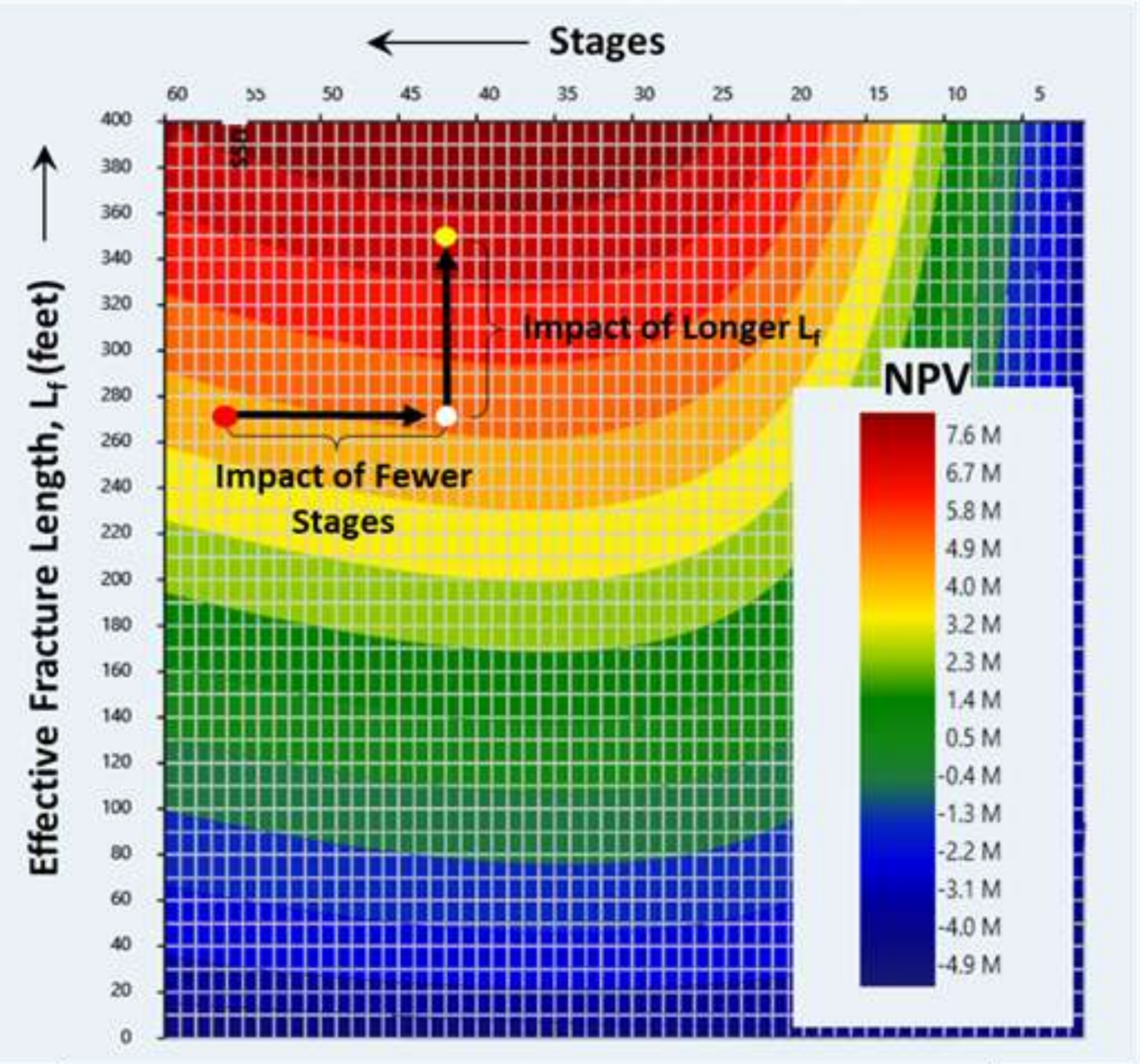


Figure 9 – Figure 5 from SPE 201716

Well Spacing Modeling

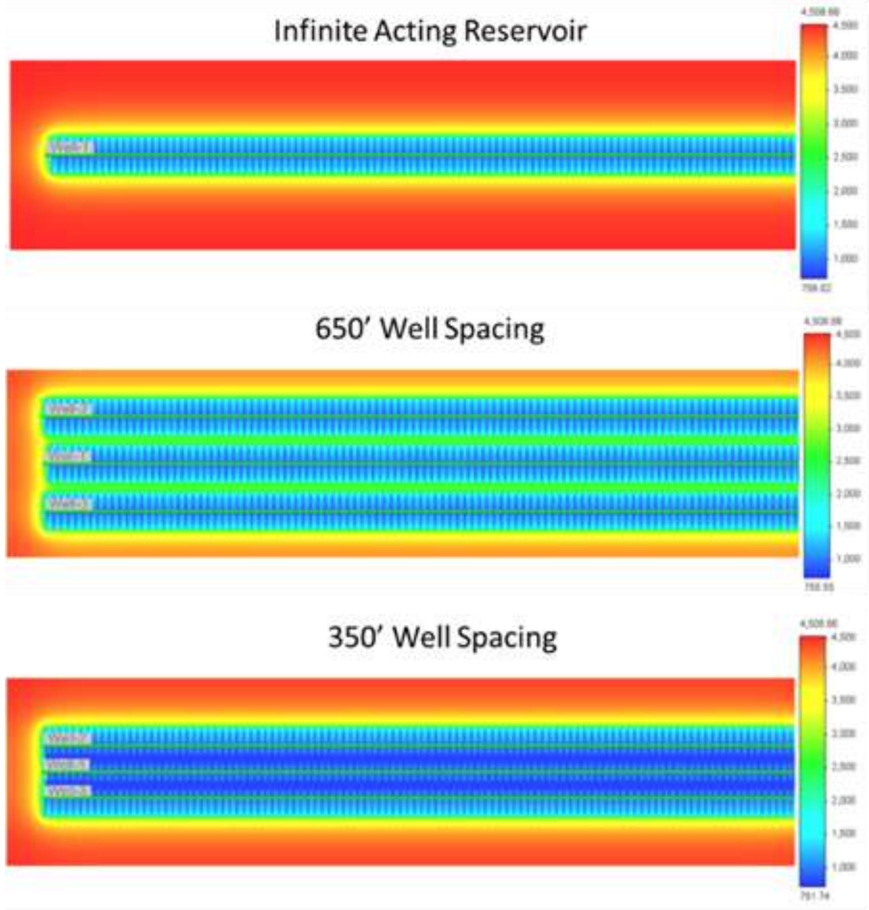


Figure 10 – Reservoir Pressure Maps Well Spacing Study

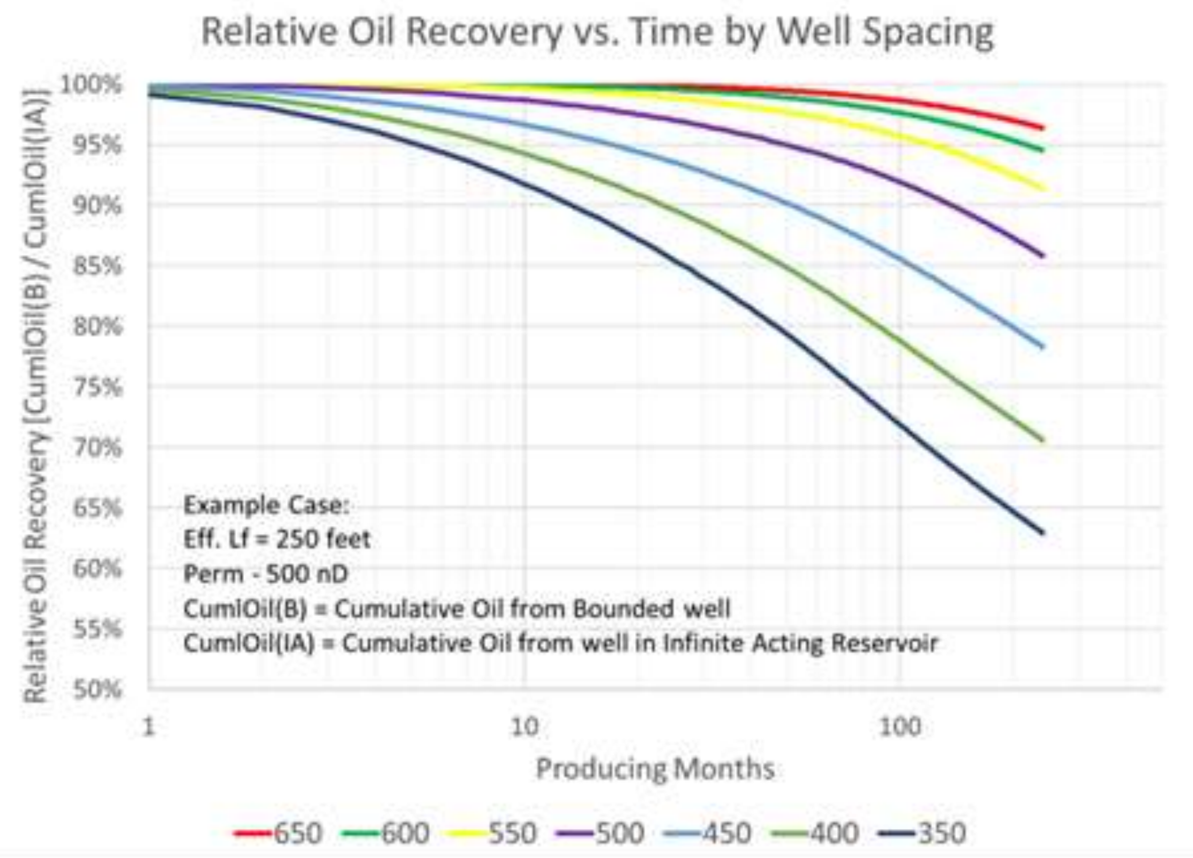


Figure 11 – Relative Oil Recovery Well Spacing Study

- Well Spacing Economics
  - Driven by
    - Knowing the effective L_f
    - Knowing the formation perm
    - Understanding inter-well interference
  - Modeling to determine optimum well spacing
    - Improves Net Value
    - Improves ROI
    - Reduces Capital Costs
    - Reduces Environment Impact

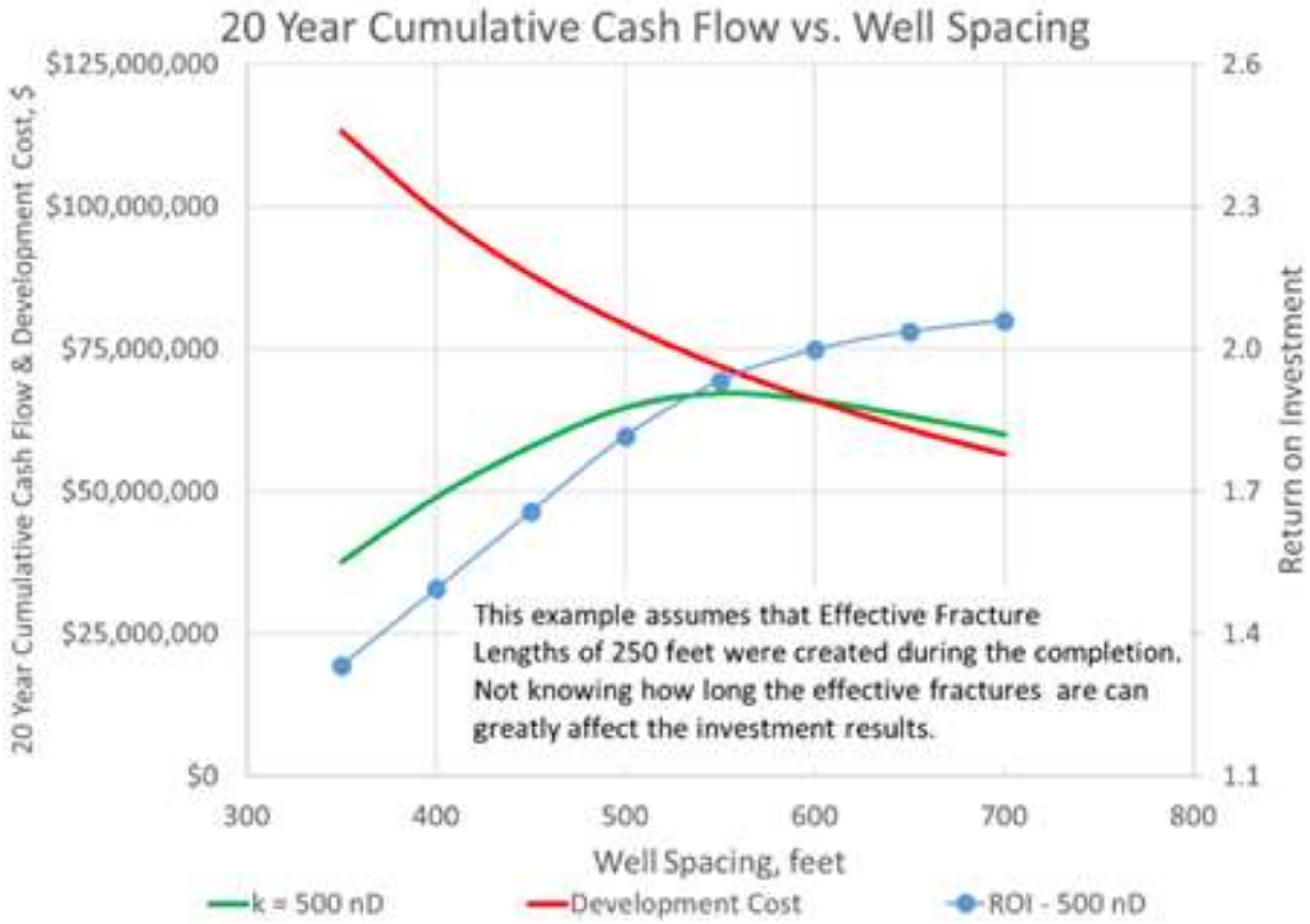


Figure 12 – Simple Economics Well Spacing Study

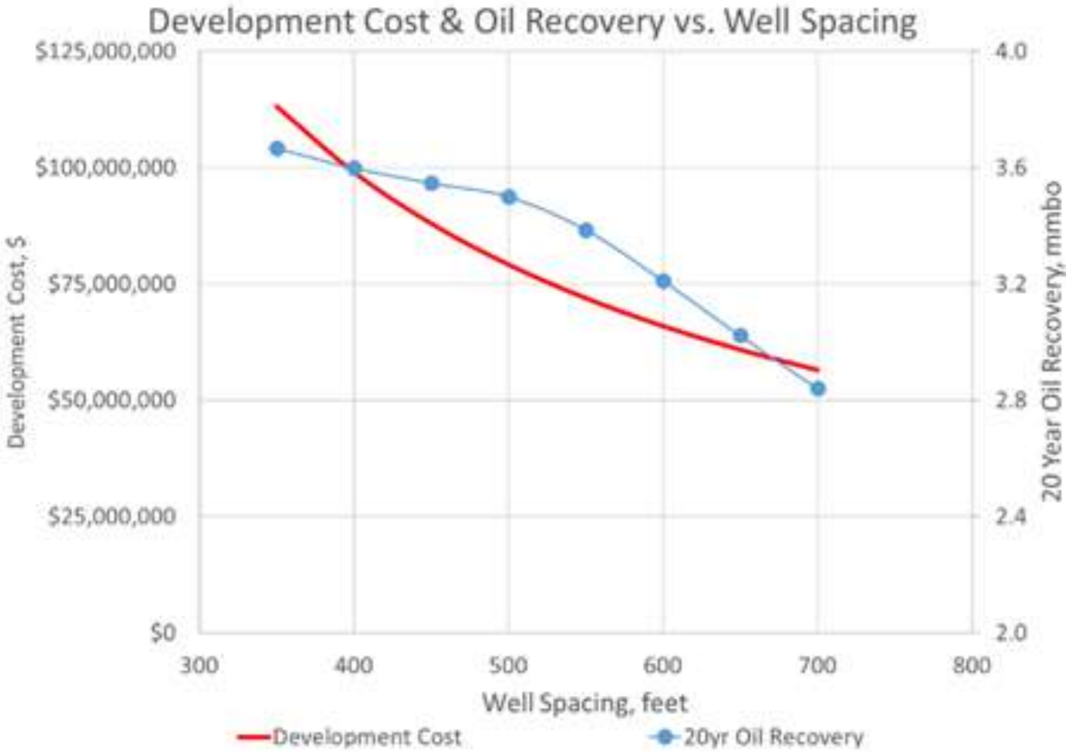


Figure 13 – Capital Costs v. EUR Well Spacing Study

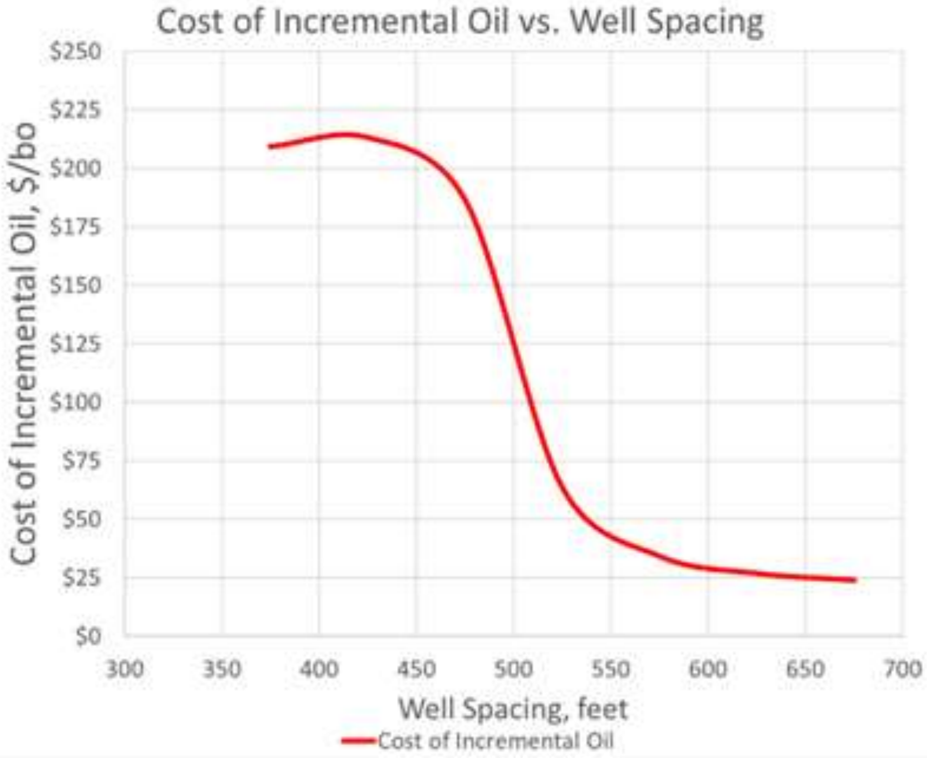


Figure 14 – Incremental Capital Cost of Next Barrel Recovered

SPE-201716-MS

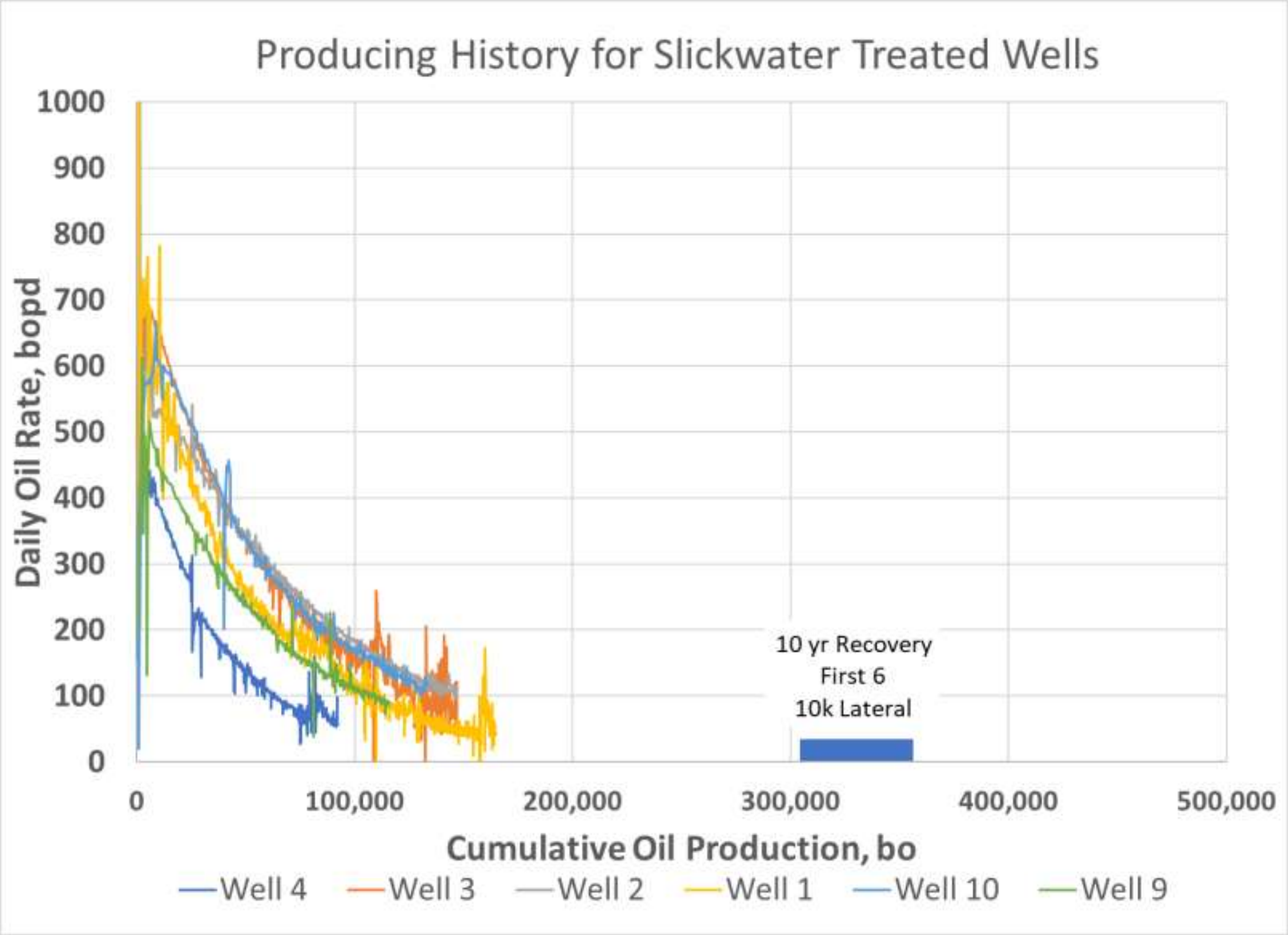
“Improving Well Economics through Reservoir Characterization and Optimized Completion Design in Horizontal, Unconventional Reservoir Development”

Authors:

Stephen Schubarth – Schubarth Inc

Tim Bozeman – MD America Energy

Robert Lestz – Greyhorse Engineering and Technology


Producing History for Slickwater Treated Wells
1000
900
800
700
600
500
400
300
200
100
0
Daily Oil Rate, bopd
0
100,000
200,000
300,000
400,000
500,000
Cumulative Oil Production, bo
10 yr Recovery
First 6
10k Lateral
Well 4
Well 3
Well 2
Well 1
Well 10
Well 9

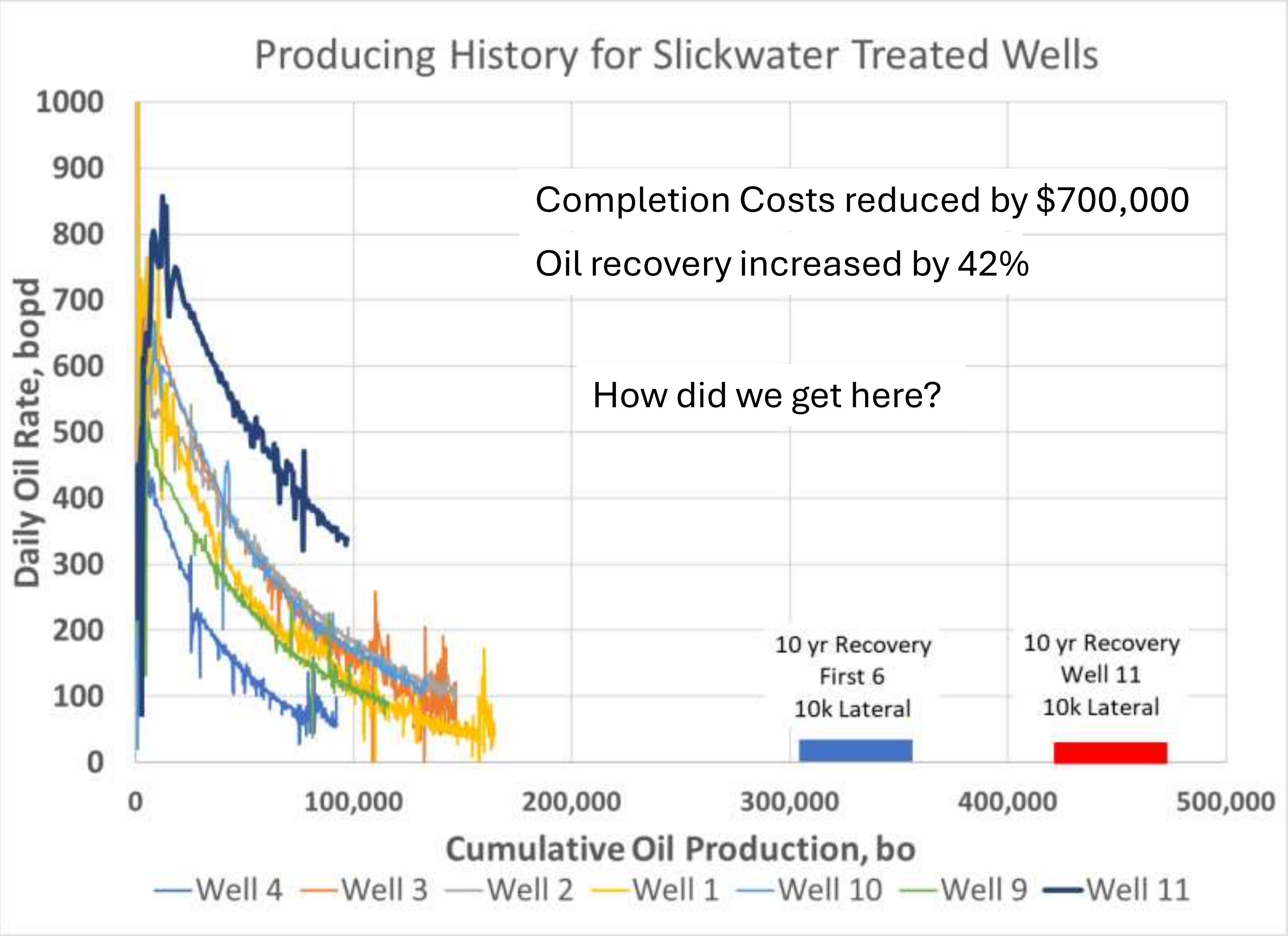

Producing History for Slickwater Treated Wells
Completion Costs reduced by $700,000
Oil recovery increased by 42%
How did we get here?
10 yr Recovery
First 6
10k Lateral
10 yr Recovery
Well 11
10k Lateral
Daily Oil Rate, bopd
Cumulative Oil Production, bo
0
100
200
300
400
500
600
700
800
900
1000
0
100,000
200,000
300,000
400,000
500,000
Well 4
Well 3
Well 2
Well 1
Well 10
Well 9
Well 11

Table 2

Summary of Reservoir Characterization Results

Well ID	Lateral Length feet	Stages	Stage Spacing feet	Sand/Stage lbs	Fluid/Stage bbls	Clusters	Perm nD	Lf feet	10 Yr Oil mbo	Fracs/Stg	Completion Cost per Lateral Foot	Oil Recovery Per Lateral Foot	Lateral Length Completed per day	Completion Cost per BO Recovered
Well 7	6536	33	198	341,191	5,713	4	1200	155	182	1		27.8		
Well 6	6433	26	247	500,903	5,846	5	750	118	138	2		21.5		
Well 5	5764	24	240	458,995	6,391	5	210	185	118	2		20.5		
Well 8	5811	30	194	375,884	7,615	6	1000	115	209	1		36.0		
Well 4	4323	26	166	472,634	11,091	9	410	260	147	2	409	34.0	903	$ 12.03
Well 3	6502	37	176	496,165	9,191	9	460	230	218	2	387	33.5	1,047	$ 11.54
Well 2	8994	58	155	436,023	8,420	9	230	255	274	2	439	30.5	966	$ 14.39
Well 1	6503	44	148	402,629	9,213	9	105	310	203	2	460	31.2	885	$ 14.74
Well 10	7259	42	173	521,999	10,162	9	370	265	256	2	393	35.3	980	$ 11.16
Well 9	6157	39	158	439,370	9,078	9	280	300	217	2	431	35.2	950	$ 12.22
Well 11														

Linear Gel

Slickwater

Late-Time Linear Flow Reached

Production History Matching was used to estimate reservoir quality and completion parameters

Permeability, # of Effective Fractures & Effective Fracture Half-length

The four wells completed with linear gel substantially underperformed those using slickwater

- Knowing the well cost for all possible completion scenarios we can run the reservoir simulator for all possible completion configurations and determine revenue generated for each scenario
- We do this for over 1000 completion design scenarios and determine the NPV for each case
- This let’s us know where the current completion design economics are and which direction we need to go to improve

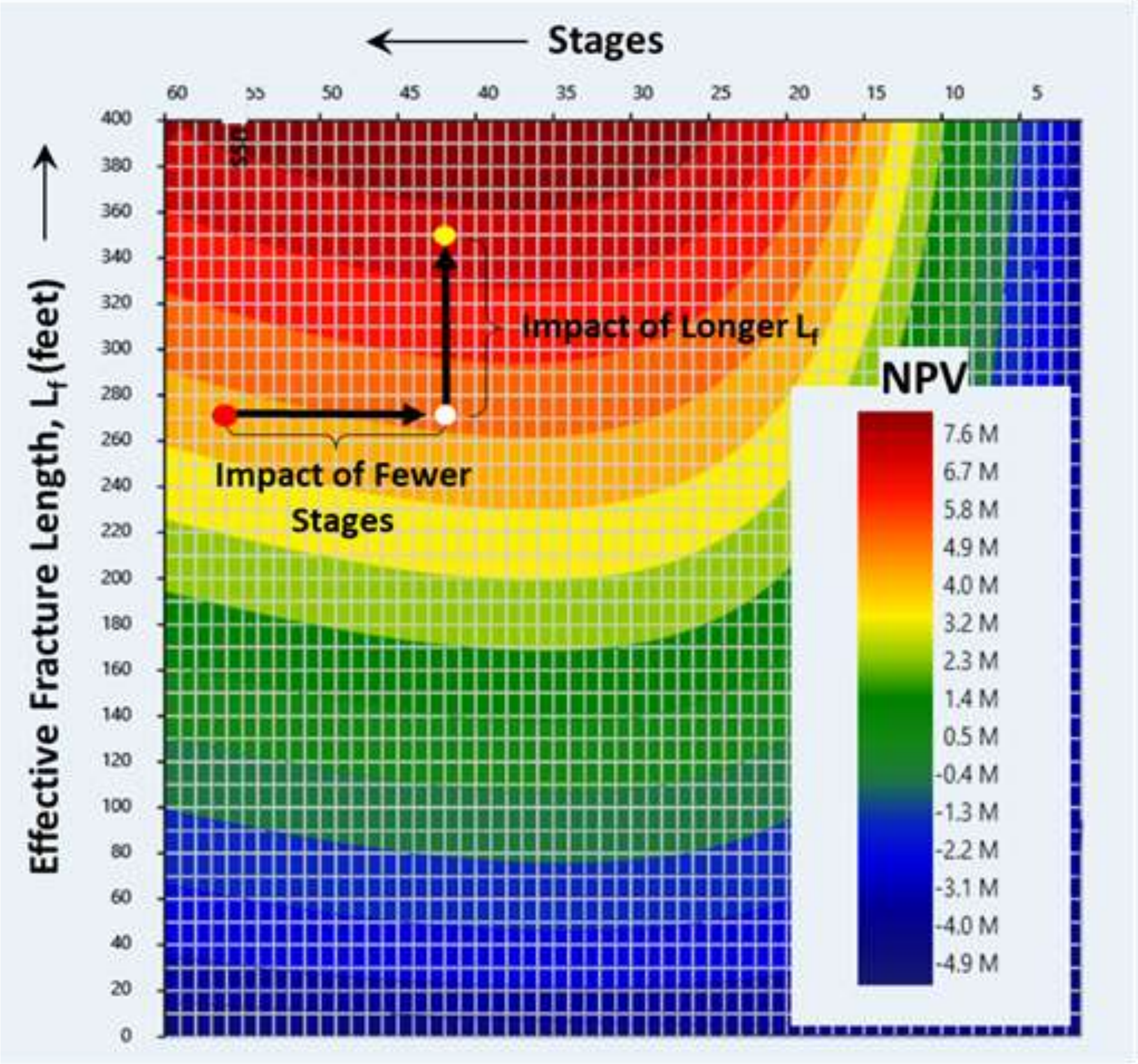


Figure 5 - NPV Road Map @ 400 nD

- Reducing the stages pumped from 57 to 42 for the designed well
- Increasing the stage volume from 525 klbs to 722 klbs to achieve a longer effective Lf
- This graph shows the match of the resulting completion
- The achieved effective length is slightly longer than predicted

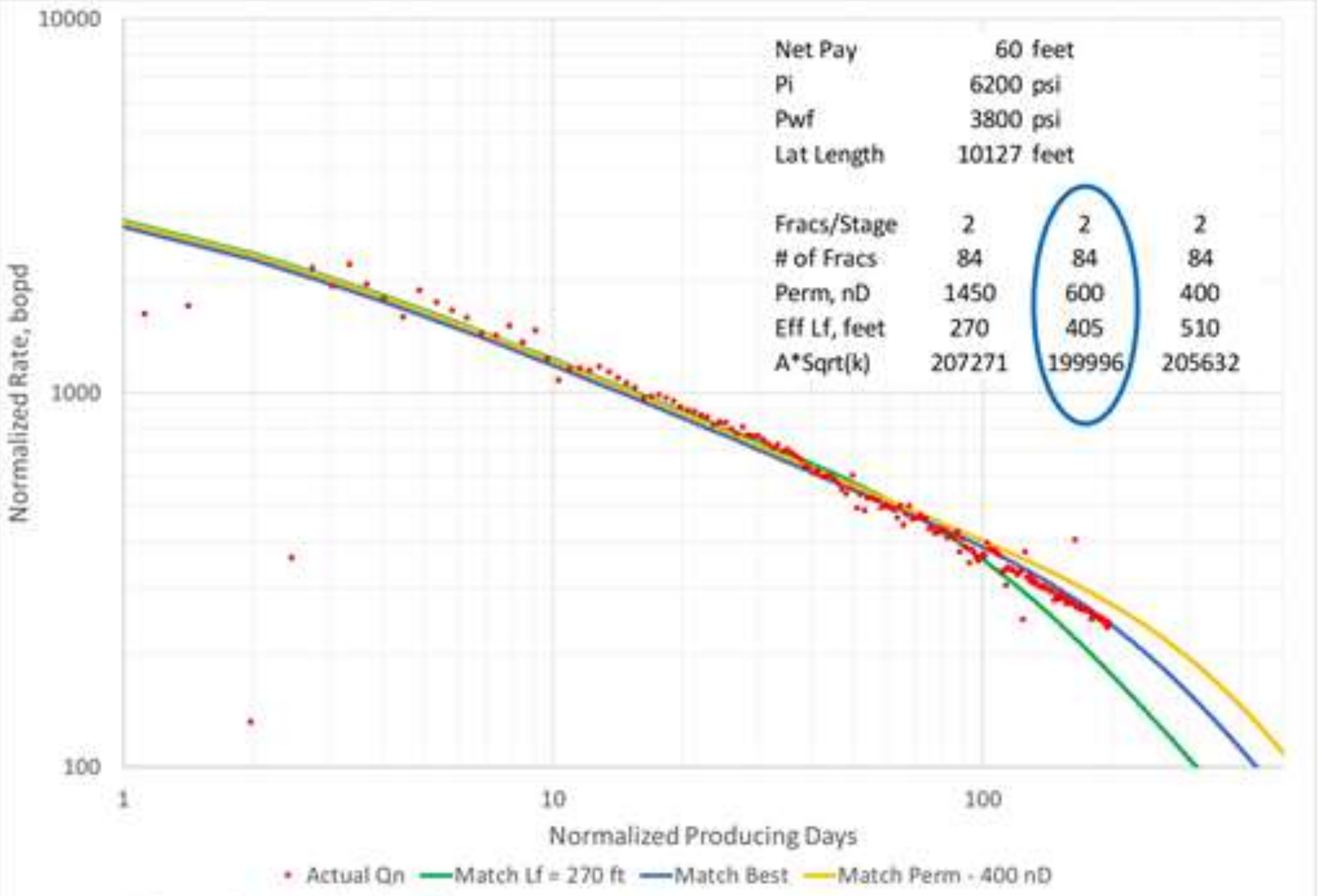


Figure 10 - Match of Well 11

Table 3

Summary of Reservoir Characterization Results with Final Well

Well ID	Lateral Length feet	Stages	Stage Spacing feet	Sand/Stage lbs	Fluid/Stage bbls	Clusters	Perm nD	Lf feet	10 Yr Oil mbo	Fracs/Stg	Completion Cost per Lateral Foot	Oil Recovery Per Lateral Foot	Lateral Length Completed per day	Completion Cost per BO Recovered
Well 7	6536	33	198	341,191	5,713	4	1200	155	182	1		27.8		
Well 6	6433	26	247	500,903	5,846	5	750	118	138	2		21.5		
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Well 1	6503	44	148	402,629	9,213	9	105	310	203	2	460	31.2	885	$ 14.74
Well 10	7259	42	173	521,999	10,162	9	370	265	256	2	393	35.3	980	$ 11.16
Well 9	6157	39	158	439,370	9,078	9	280	300	217	2	431	35.2	950	$ 12.22
Well 11	**10127**	**42**	**241**	**721,945**	**13,700**	**9**	**600**	**405**	**479**	**2**	**314**	**47.3**	**1,154**	**$ 6.63**

Linear Gel

Slickwater

Late-Time Linear Flow Reached

Well 11 substantially - reduced completion cost per lateral foot

increased oil recovery per lateral foot

reduced completion cost per bbl of oil recovered by almost 50%

- Reservoir simulation shows the pressure maps for the completion scenarios
- The redesigned well on top, the current design well on bottom.
- Achieving a larger SRV will allow for fewer wells to be needed to drain available acreage, further reducing capital costs

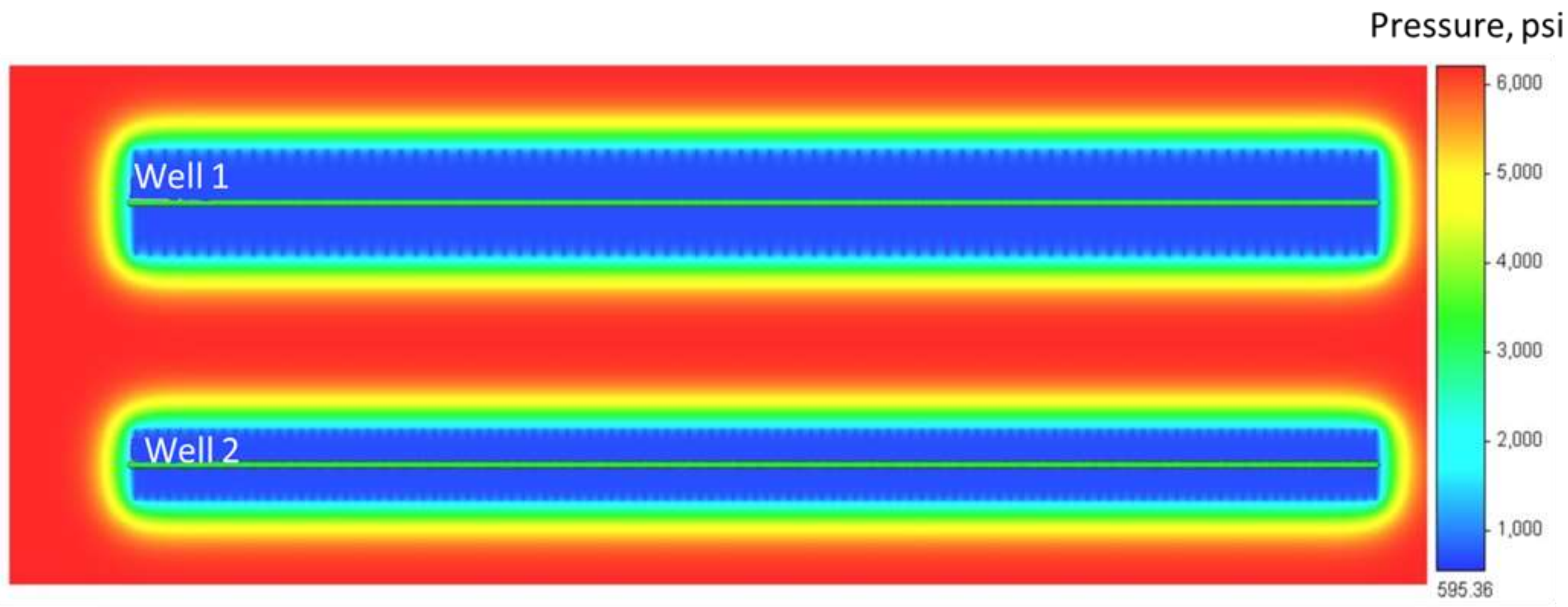


Figure 14 – Pressure Map @ 20 years – 400 nD reservoir

SRV size for redesigned well

SRV size for current design well

Environmental Impact of Optimized Design (Eagleford) Stage & Well Spacing

***assuming the development of 50,000 acres**

- Reduced number of wells to develop acreage – **234 vs. 335**
- Reduced frac water volume needed by **80 million barrels**
- Reduced frac sand needed by **3.2 billion pounds**
- Reduced diesel fuel needed by **15 million gallons**
- Reduced CO_2 emissions from diesel fuel by **195 thousand tons**

- Reduced capital needed to develop acreage - **$932 million**

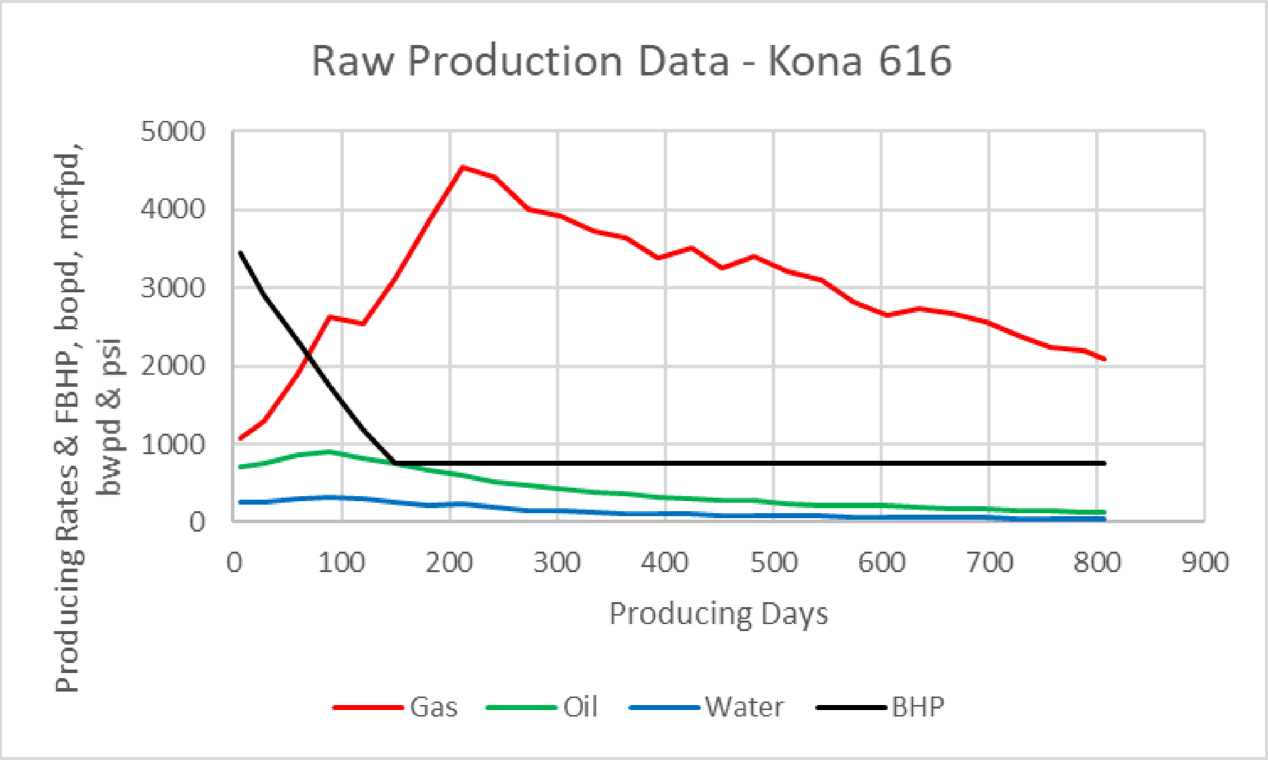
DJ Basin Operator
Dunn & Kona Pad Evaluation

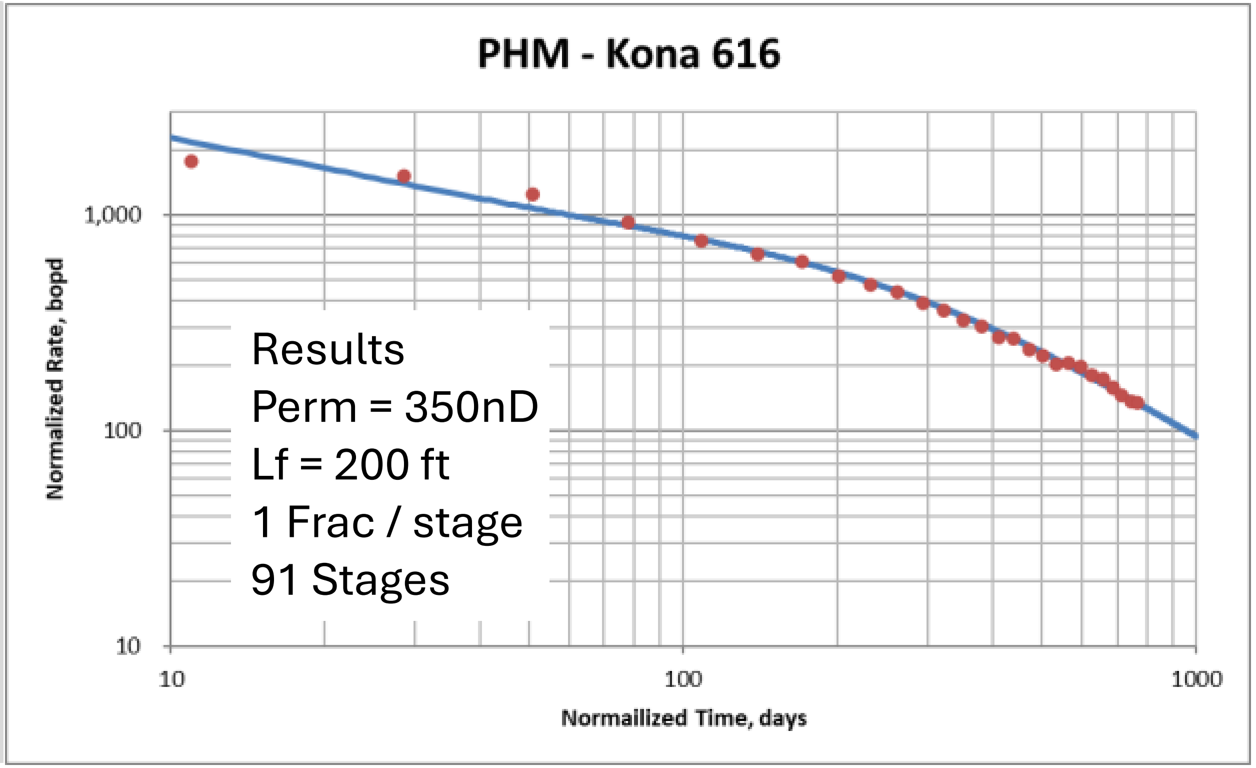
Schubarth Inc

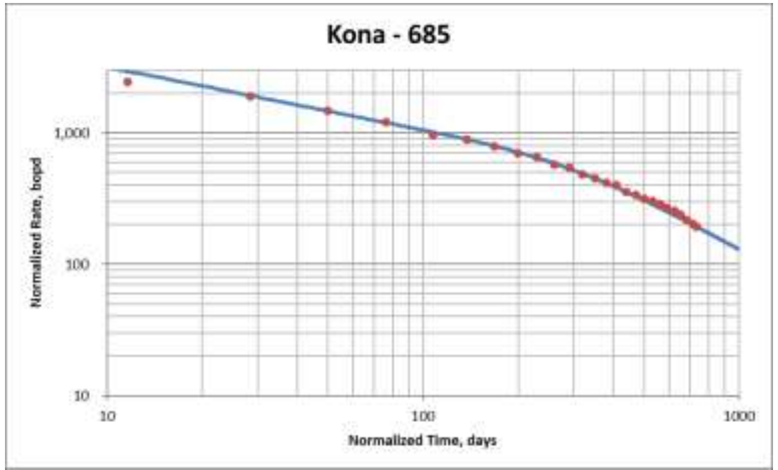
April 2021

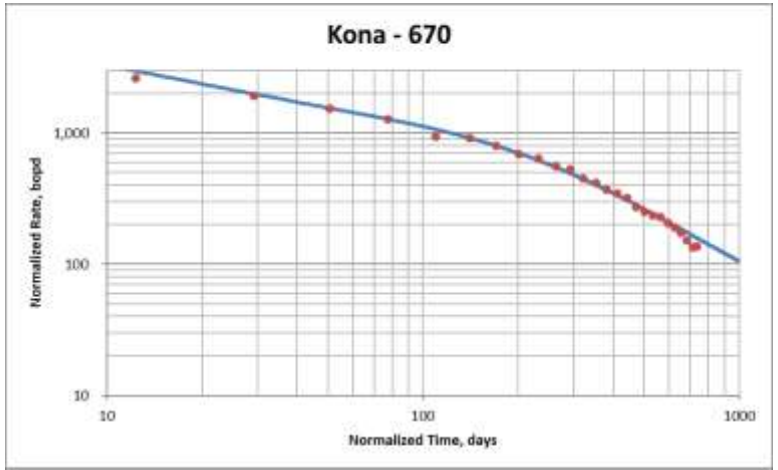
Example Production History Match

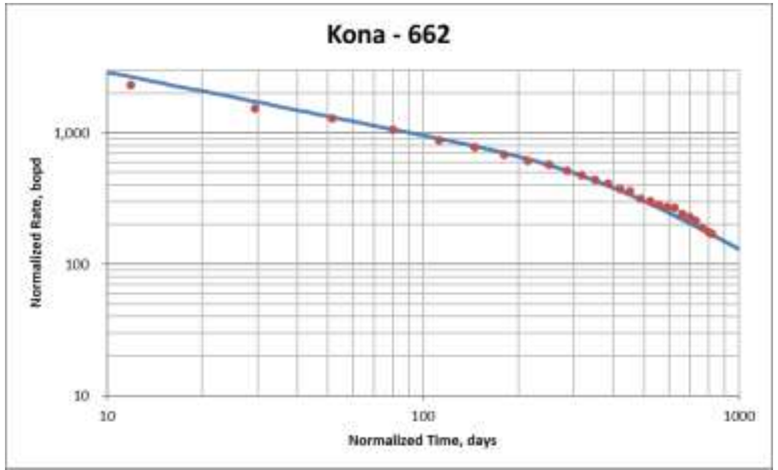
- Raw production data and Flowing Surface Pressures
- Calculate FBHP
- Normalize Producing Rates and Producing Times
- Production History Match Normalized data with model






Kona - 685
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days


Kona - 670
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days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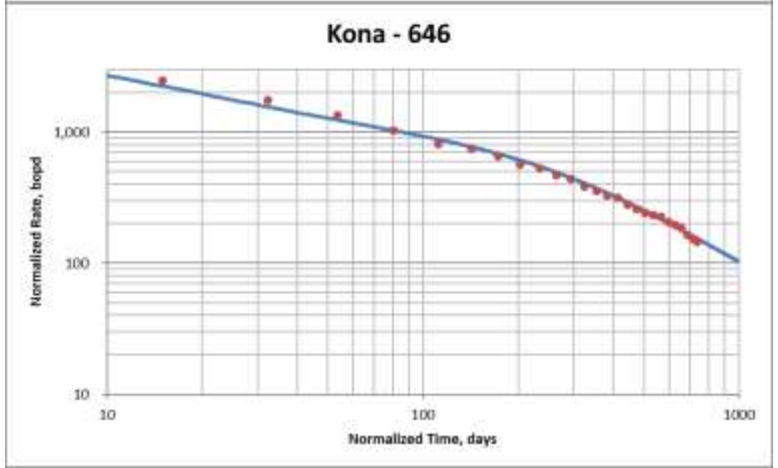
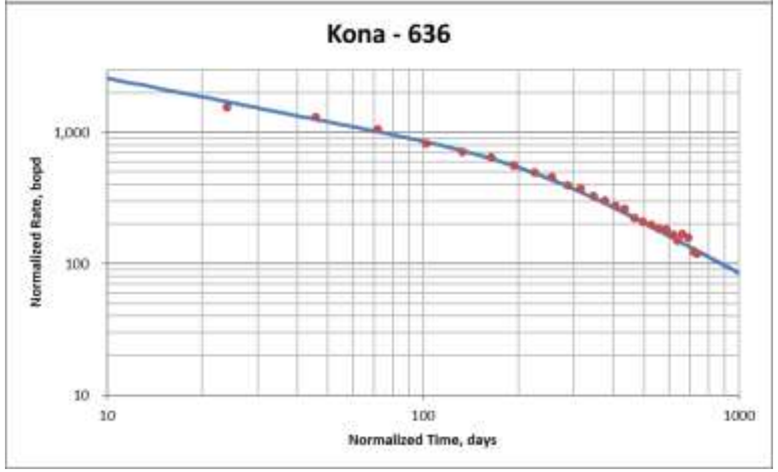
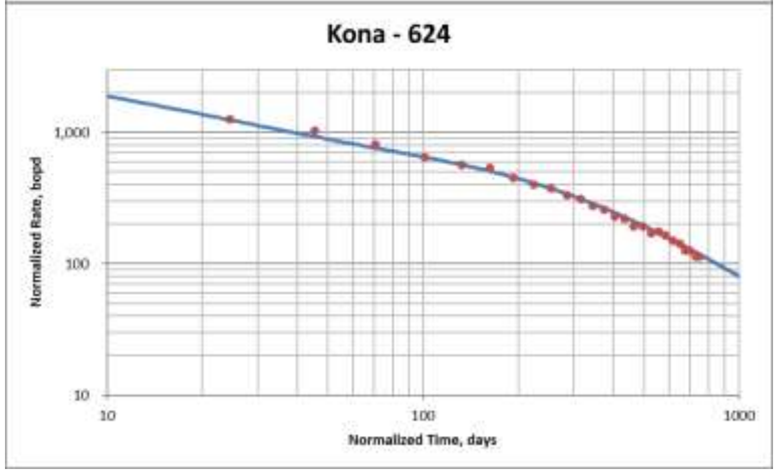
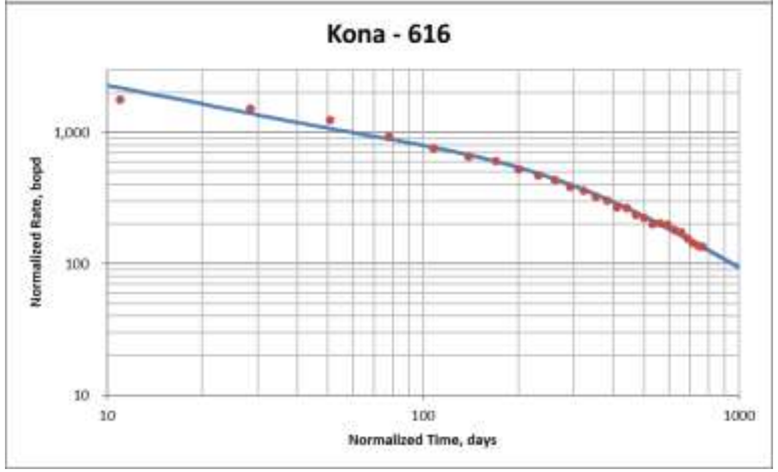
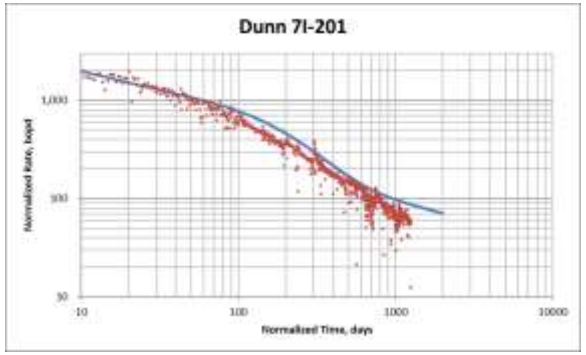
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days

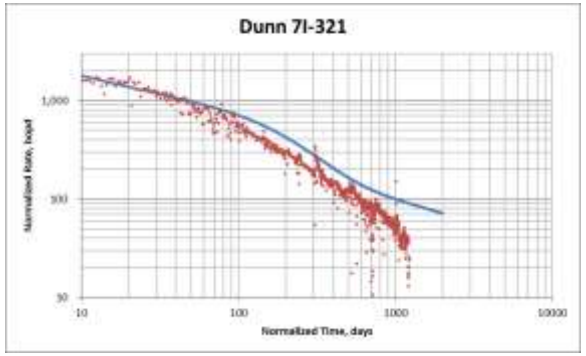

Kona - 646
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days


Kona - 636
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days


Kona - 624
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days


Kona - 616
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normalized Time, days


Dunn 7I-201
Normalized Rate, bopd
Normalized Time, days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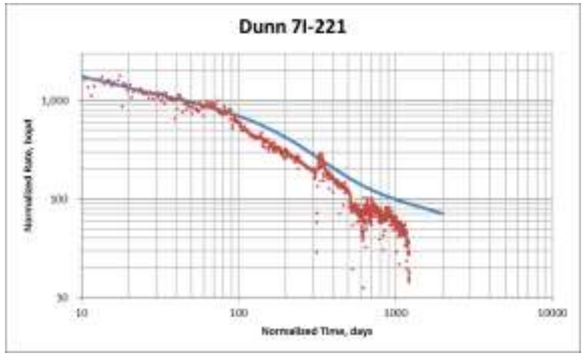
Normalized Time, days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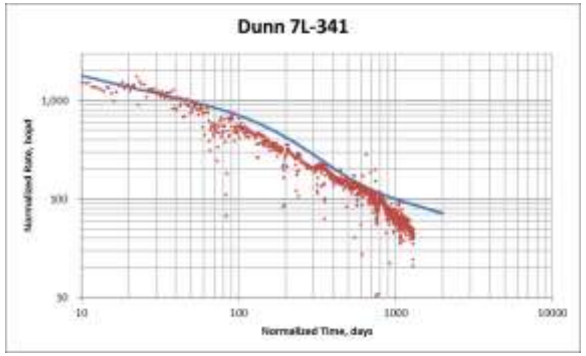
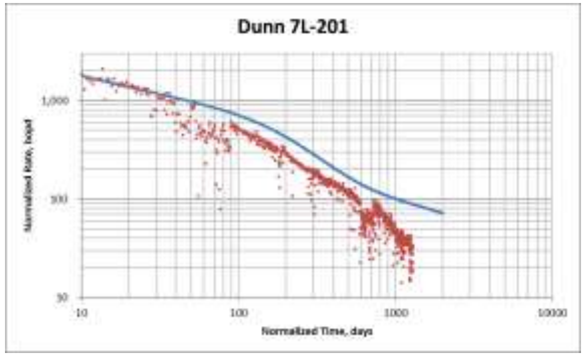
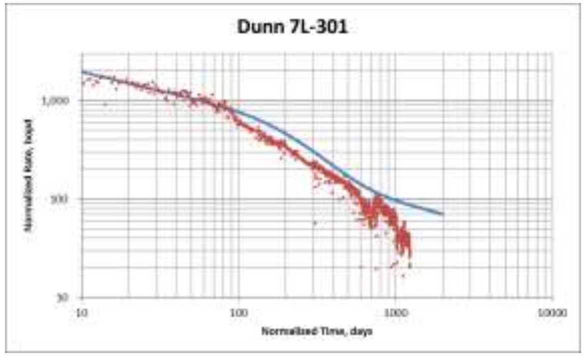
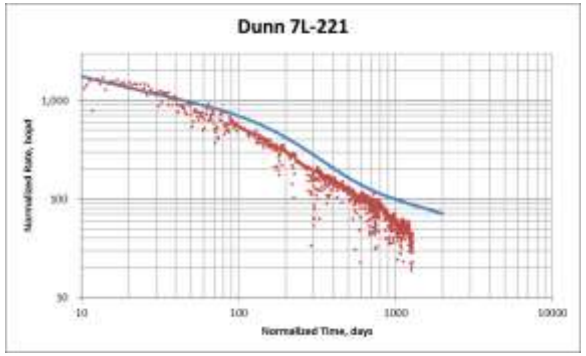
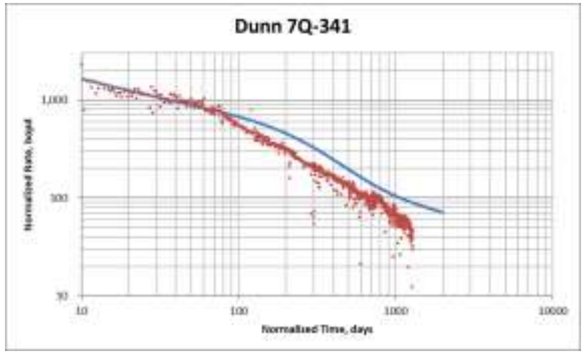
Normalized Rate, bopd
Normalized Time, days

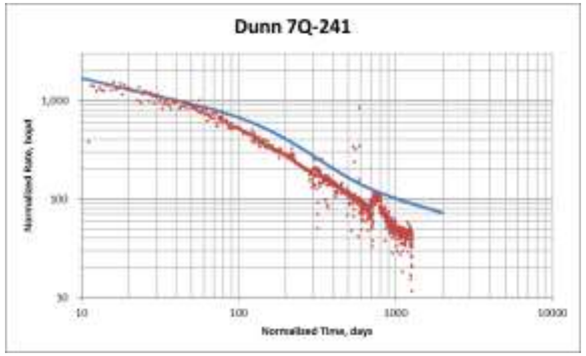

Dunn 7L-341
Normalized Rate, bopd
Normalized Time, days

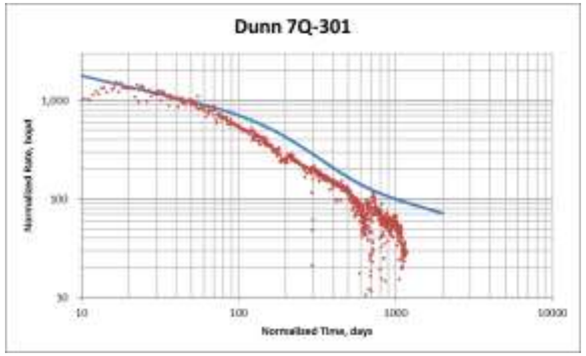

Dunn 7L-201
Normalized Rate, bopd
Normalized Time, days

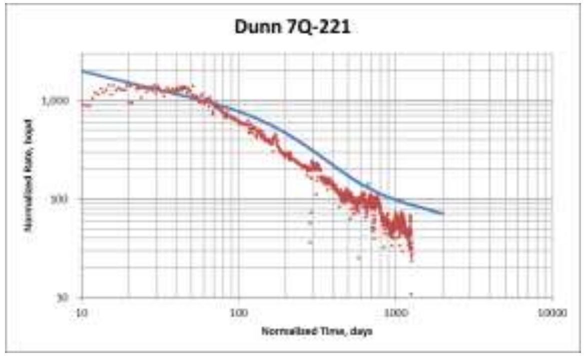

Dunn 7L-301
Normalized Rate, bopd
Normalized Time, days


Dunn 7L-221
Normalized Rate, bopd
Normalized Time, days

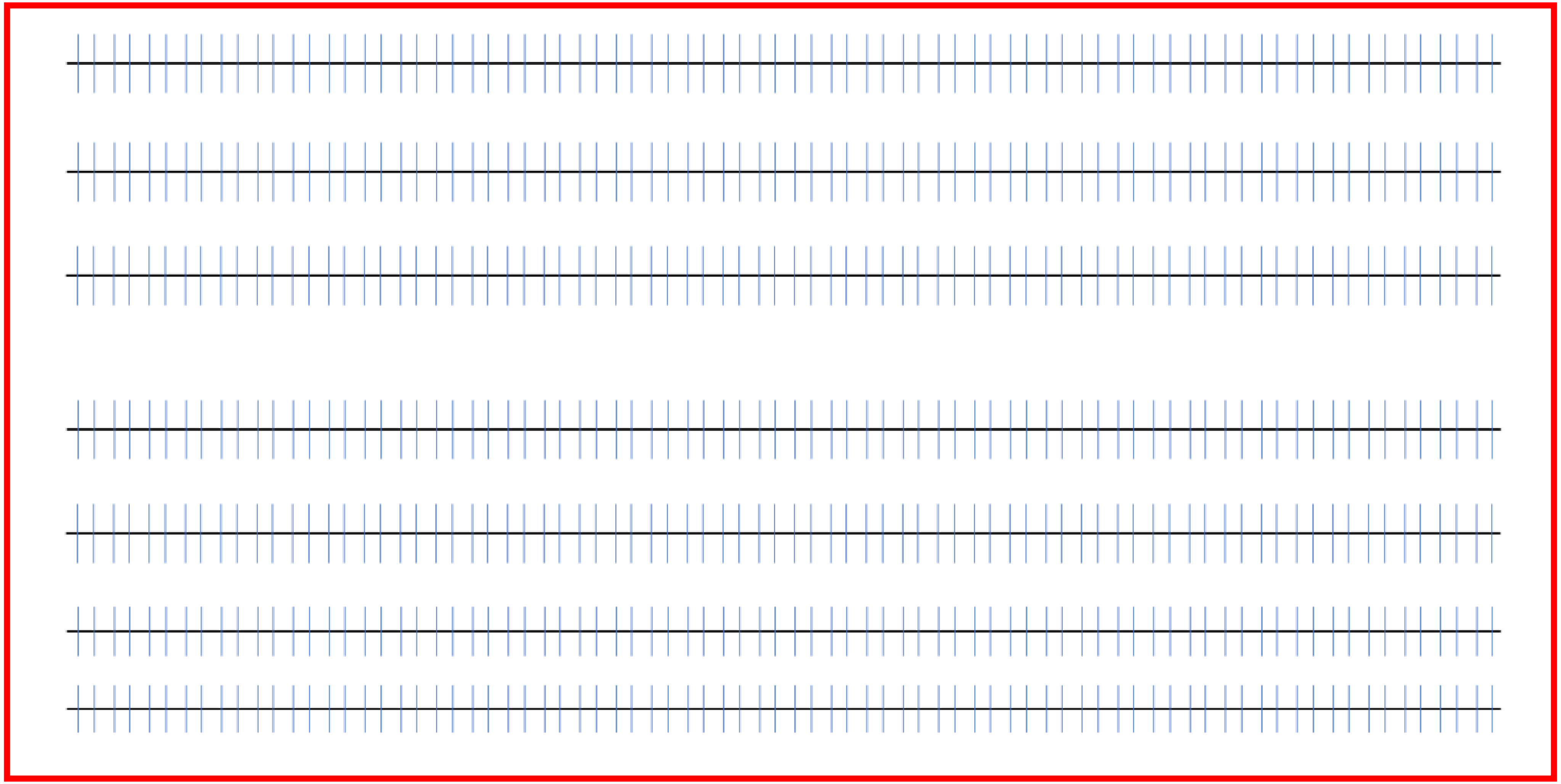

Dunn 7Q-341
Normalized Rate, bopd
Normalized Time, days


Dunn 7Q-241
Normalized Rate, bopd
Normalized Time, days


Dunn 7Q-301
Normalized Rate, bopd
Normalized Time, days


Dunn 7Q-221
Normalized Rate, bopd
Normalized Time, days

Kona Pad well spacing w/ Lf



Dunn Pad well spacing w/ Lf

Summary

- Dunn Pad well production indicates interference between offset wells before interference between dominate stage fracs
- Kona Pad well production indicates interference between dominate stage fracs and no interference between wells
- Formation permeability is estimated to be between 150 – 450 nD
- Dunn Pad production indicates fewer stages could be pumped at this well spacing without loss of recovery (saving capital)

Project Results Summary

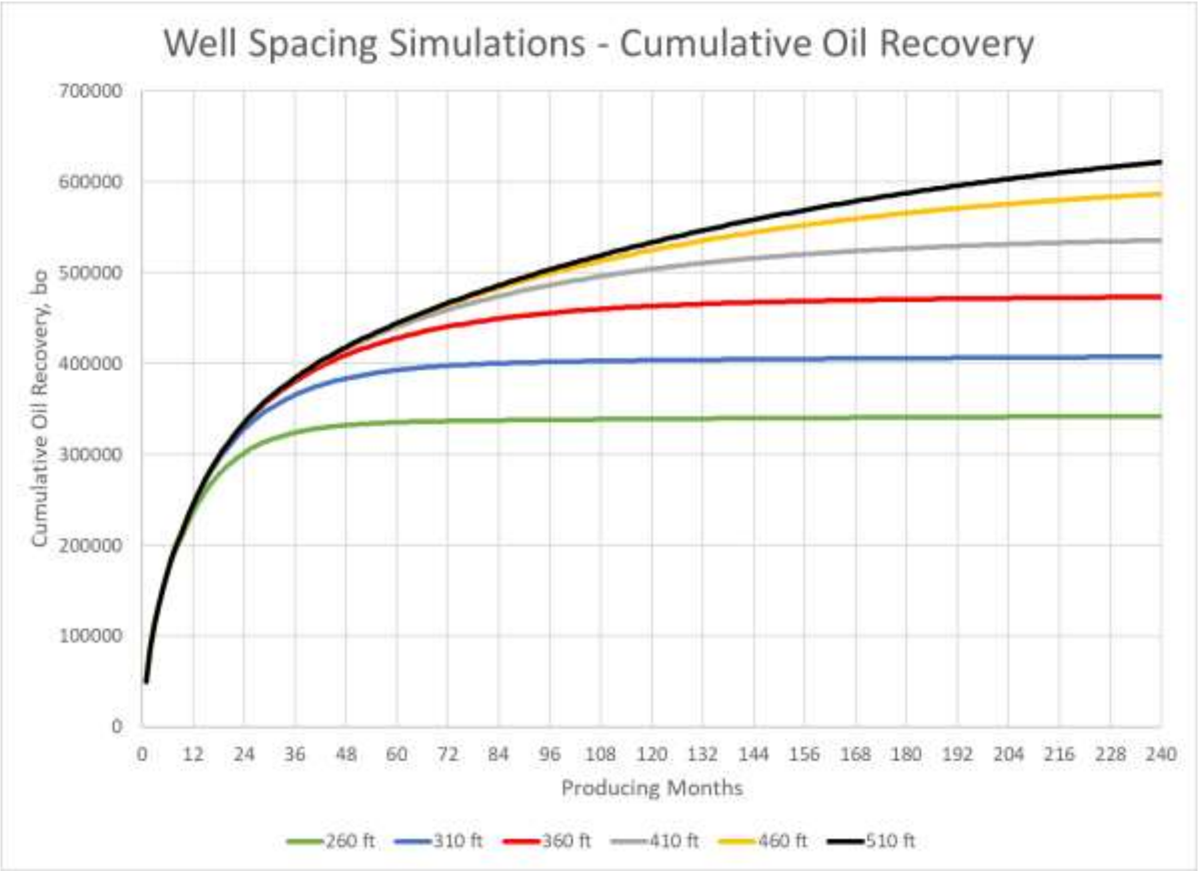
Pad	Well #	Compl Date	IP540 Oil	540BO / ft	end depth	start depth	length	Sand #	Sand #/ft	Fluid	Bbbl/ft	#/bbl	stages	stage length	Zone	#/stage	Contacted Net Pay	Fracs/Stg	Perm	Lf	EUR	b	Rem
Kona	a19-685	Jan-18	360.2	34.6	18,661	8,242	10,419	29,152,250	2,798	976,740	94	0.71	44	237	Nio C	662,551	105	2	300	280	710	0.7	235
Kona	a19-670	Jan-18	360.8	33.9	18,227	7,576	10,651	29,152,250	2,737	976,740	92	0.71	44	242	Nio B	662,551	105	2	480	230	585	0.7	147
Kona	a19-662	Dec-17	348.7	35.2	17,412	7,502	9,910	29,616,188	2,989	978,516	99	0.72	44	225	Codell	673,095	115	2	220	280	679	0.7	210
Kona	a19-646	Dec-17	317.8	29.6	18,039	7,312	10,727	31,382,201	2,926	1,021,939	95	0.73	44	244	Nio C	713,232	95	2	400	230	572	0.7	173
Kona	a19-636	Nov-17	282.6	25.9	18,236	7,327	10,909	39,844,907	3,652	1,330,817	122	0.71	62	176	Nio B	642,660	95	2	220	210	507	0.7	147
Kona	a19-624	Nov-17	229.0	25.4	16,321	7,317	9,004	34,854,455	3,871	1,118,923	124	0.74	78	115	Codell	446,852	95	1	300	215	426	0.7	124
Kona	a19-616	Nov-17	278.3	26.2	17,752	7,112	10,640	39,469,757	3,710	1,282,699	121	0.73	91	117	NioC	433,734	95	1	350	200	512	0.7	157
Dunn	7I-201	May-17	215.4	22.3	16,724	7,078	9,646	10,830,000	1,123	193,304	20	1.33	57	169	Nio B	190,000	120	2	300	127	382	0.7	95
Dunn	7I-321	May-17	185.8	19.2	16,769	7,103	9,666	10,434,000	1,079	196,561	20	1.26	57	170	NioC	183,053	120	2	300	112	306	0.7	73
Dunn	7I-221	Apr-17	191.4	20.0	16,679	7,088	9,591	10,595,000	1,105	191,756	20	1.32	56	171	Nio B	189,196	120	2	300	112	316	0.7	67
Dunn	7L-341	May-17	181.5	18.8	16,768	7,098	9,670	10,161,500	1,051	195,942	20	1.23	57	170	NioC	178,272	120	2	300	112	354	0.7	99
Dunn	7L-201	May-17	163.3	16.8	16,700	6,964	9,736	10,490,320	1,077	191,525	20	1.30	57	171	Nio B	184,041	120	2	300	112	268	0.7	54
Dunn	7L-301	May-17	208	21.5	16,760	7,076	9,684	10,842,000	1,120	198,058	20	1.30	57	170	NioC	190,211	120	2	300	127	334	0.7	69
Dunn	7L-221	May-17	174.5	18.2	16,679	7,088	9,591	10,595,000	1,105	191,756	20	1.32	56	171	Nio B	189,196	120	2	300	112	303	0.7	69
Dunn	7Q-341	May-17	182.9	19.0	16,775	7,158	9,617	9,551,400	993	196,874	20	1.16	47	205	NioC	203,221	120	2	300	127	338	0.7	88
Dunn	7Q-241	May-17	171	17.6	16,827	7,129	9,698	10,268,700	1,059	198,393	20	1.23	57	170	Nio B	180,153	120	2	300	105	303	0.7	75
Dunn	7Q-301	May-17	175.8	18.2	16,943	7,269	9,674	10,373,000	1,072	196,237	20	1.26	57	170	NioC	181,982	120	2	300	112	283	0.7	64
Dunn	7Q-221	May-17	189.4	19.5	17,007	7,284	9,723	10,732,190	1,104	196,881	20	1.30	57	171	Nio B	188,284	120	2	300	127	321	0.7	75

Best Kona Wells – Avg #/ft = 2867 Avg EUR = 637 mbo

Worst Kona Wells – Avg #/ft = 3744 Avg EUR = 482 mbo

Well Spacing Optimization for Future Pads

- Assume the same reservoir and completion properties from Phase 1
- Build bounded well simulation runs using 310, 360, 410, 460 & 510 ft well spacings
- Run model and evaluate recovery using 200 ft stage spacing
- Perform economics on each case assuming development of 1280 acre Pad
- Compare results

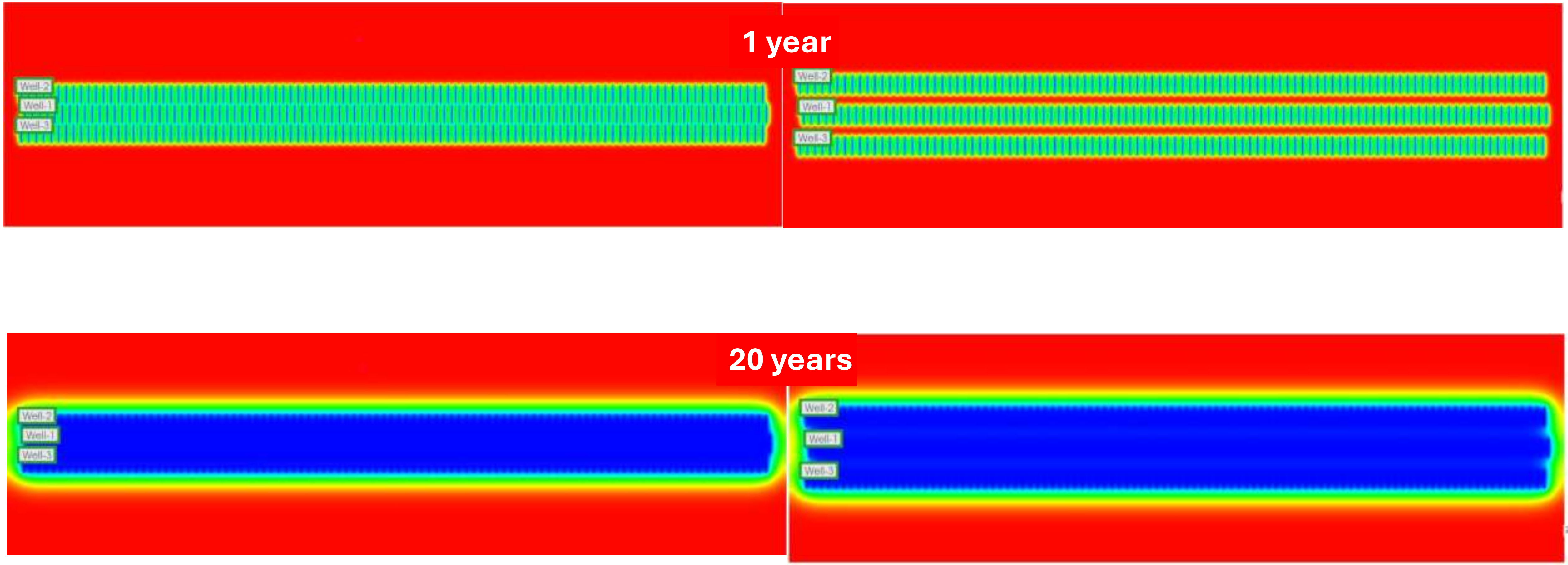


Well Spacing, ft	260	310	360	410	460	510
Well/Section	20	17	15	13	11	10
CCF/well	$ 14,376,158	$ 17,733,370	$ 20,856,549	$ 23,784,240	$ 26,521,293	$ 28,471,739
NPV/well	$ 12,989,190	$ 15,551,608	$ 17,430,734	$ 18,660,661	$ 19,436,249	$ 19,855,243
OilRec/well, mbo	342	408	473	536	587	622
CapEx/Pad, $mm	$ 75.91	$ 63.67	$ 54.82	$ 48.14	$ 42.91	$ 38.70
CCF/Pad, $mm	$ 291.95	$ 302.04	$ 305.90	$ 306.29	$ 304.42	$ 294.77
NPV/Pad, $mm	$ 263.78	$ 264.88	$ 255.65	$ 240.31	$ 223.09	$ 205.56
OilRec/Pad, mmbo	6.96	6.94	6.94	6.90	6.73	6.44
ROI	4.85	5.74	6.58	7.36	8.10	8.62
DevCost/Bo	$ 10.91	$ 9.17	$ 7.90	$ 6.98	$ 6.37	$ 6.01

- Recommend developing the next 1280 acre pad on 410 ft well spacing
- Recommendation should:
  - Reduce CapEx required for development by $27.77 million
  - Recovers 99% of oil recovered from Future Pad Spacing (assuming 10k lateral)
  - Cumulative Cash Flow maximized
  - ROI increased from 4.85 to 7.36
  - Development cost per BO recovered decreases from $10.91 to 6.98

Pressure Maps of Well Spacing Simulations

260 ft Spacing | 410 ft Spacing



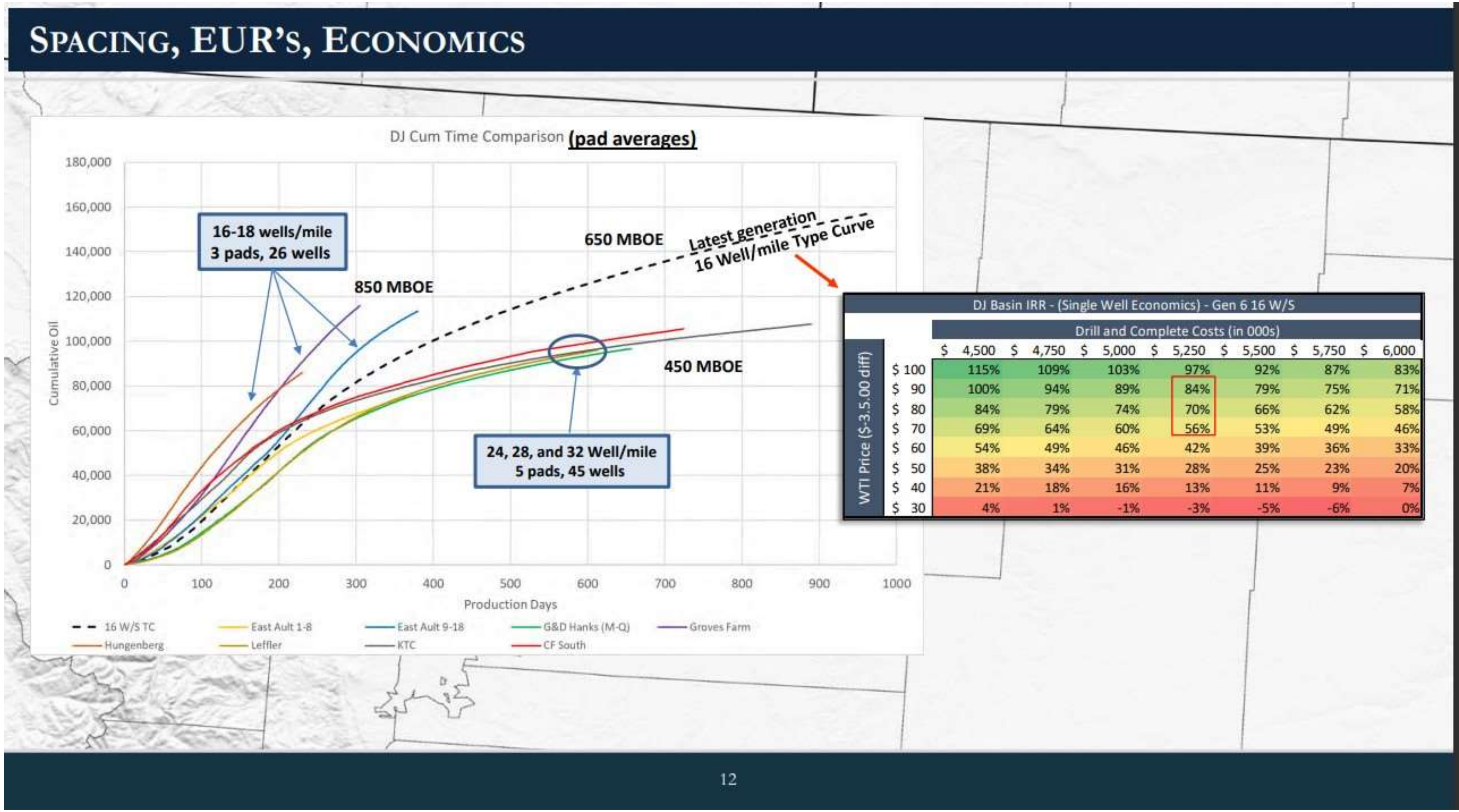
Summary

- Significant CapEx savings (~$1 million/well) can be achieved in the completion of Future Pad wells by increasing stage spacing to 240 ft with no loss in oil recovery
- Increasing well spacing on future Pad developments to 410 feet saves over $28 million on the development of 1280 acres without any loss in oil recovery/section. Significant improvement in ROI results.

Results

- Increased Well Spacing
- Increased Stage Spacing
- Increased Job Size

- Increased EUR/well
- Reduced Capital Expense greatly
- No loss in total recovery per section



DJ Basin IRR - (Single Well Economics) - Gen 6 16 W/S

WTI Price ($-3.5.00 diff)	Drill and Complete Costs (in 000s)						
	$ 4,500	$ 4,750	$ 5,000	$ 5,250	$ 5,500	$ 5,750	$ 6,000
$ 100	115%	109%	103%	97%	92%	87%	83%
$ 90	100%	94%	89%	84%	79%	75%	71%
$ 80	84%	79%	74%	70%	66%	62%	58%
$ 70	69%	64%	60%	56%	53%	49%	46%
$ 60	54%	49%	46%	42%	39%	36%	33%
$ 50	38%	34%	31%	28%	25%	23%	20%
$ 40	21%	18%	16%	13%	11%	9%	7%
$ 30	4%	1%	-1%	-3%	-5%	-6%	0%

Summary

- Optimizing economics on horizontal multi-stage completions can be a complex process
- Production history matching can determine the primary reservoir/completion properties we need to know:
  - Formation permeability
  - Effective fracture half-length achieved
  - Number of dominant producing fractures
- Millions of dollars of capital costs can be Reduced and Profit added
- A major **positive Environmental Impact** can be achieved

Thank you

Stephen Schubarth

President

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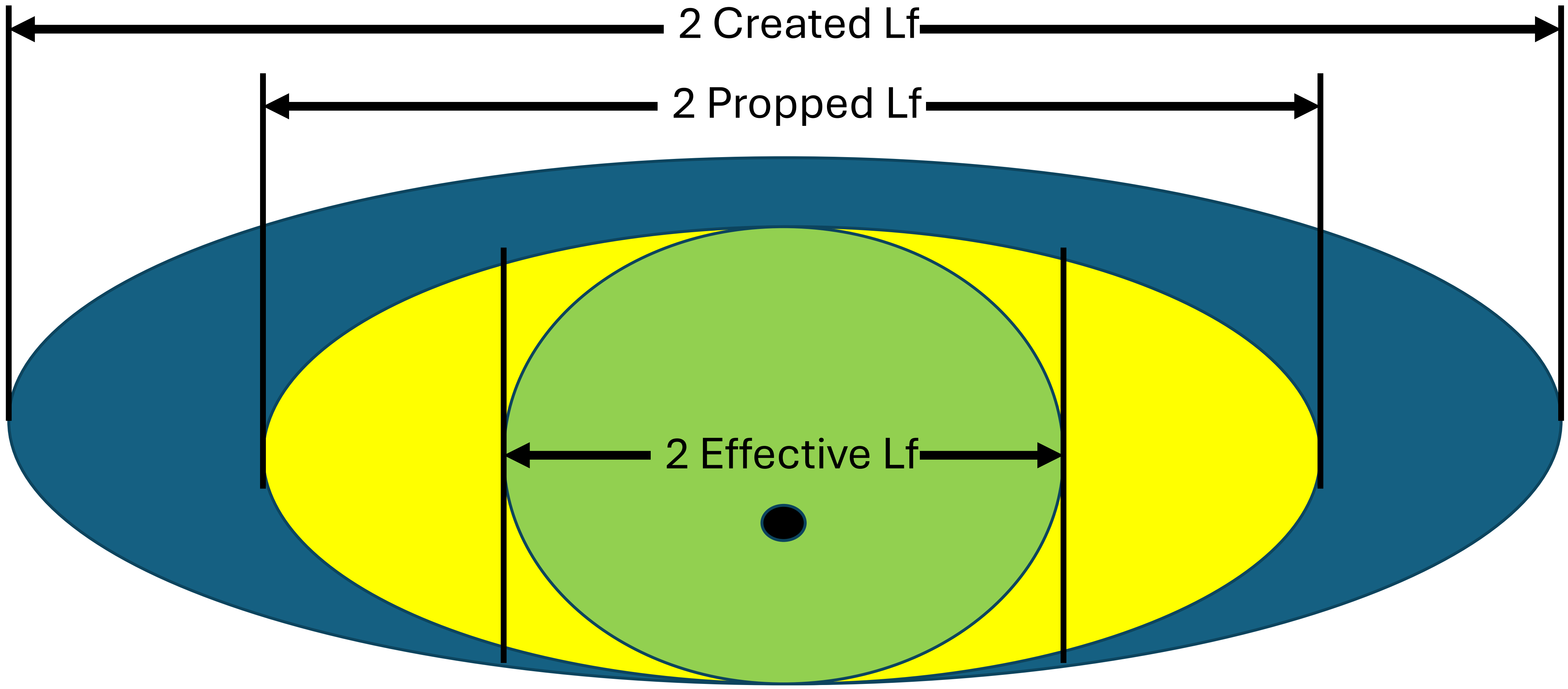
Before we move on – Defining Frac Length



Frac Design

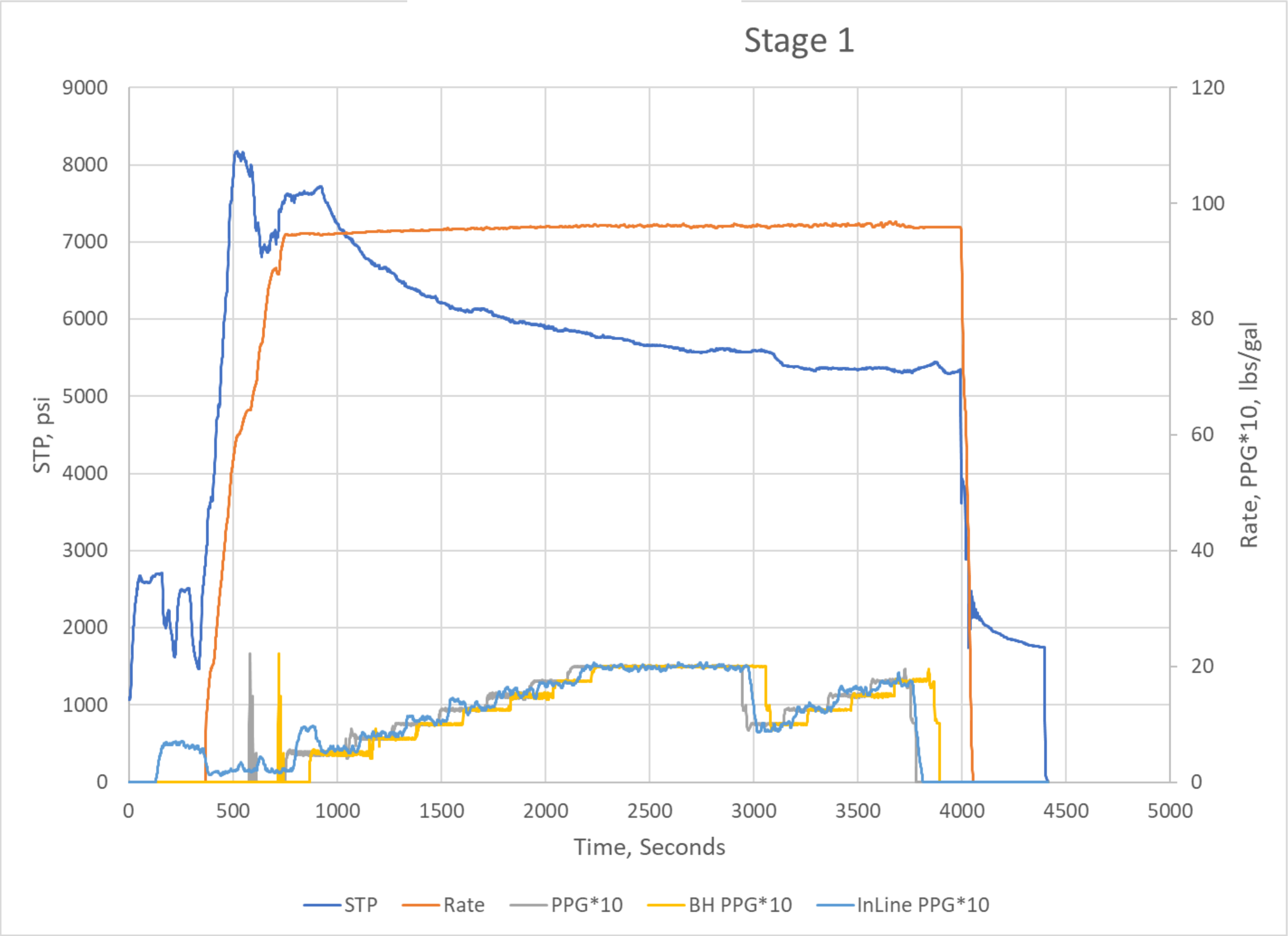
Sand Pumped	500,000	lbs
Water Pumped	10,000	bbls
Pump Rate	90	BPM
Perf Clusters	9	

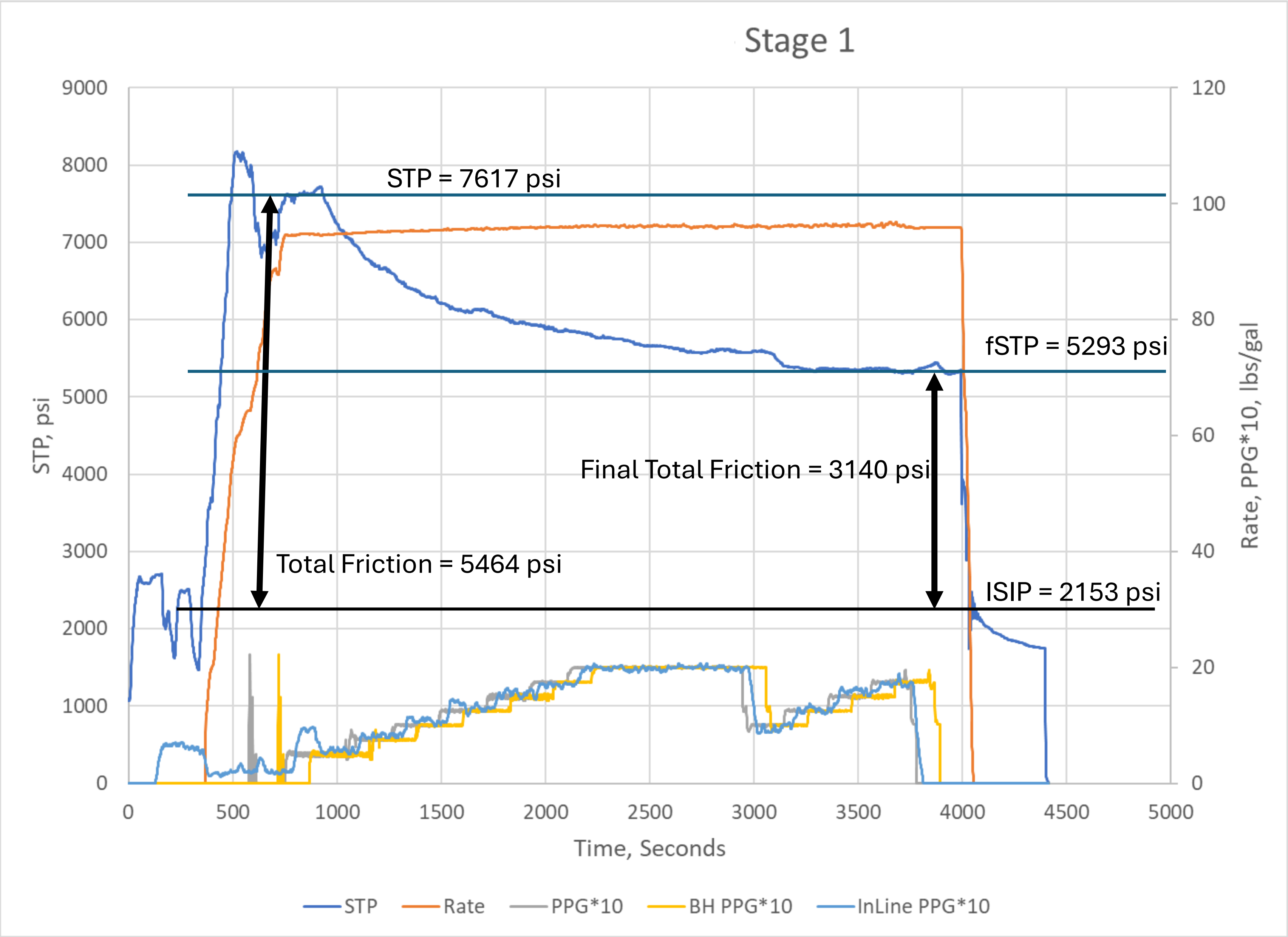
Perf Efficiency	11%	22%	33%	44%	56%	67%	78%	89%	100%
Sand/Frac	500,000	250,000	166,667	125,000	100,000	83,333	71,429	62,500	55,556
Water/Frac	10,000	5,000	3,333	2,500	2,000	1,667	1,429	1,250	1,111
Pump Rate/Frac	90	45	30	23	18	15	13	11	10

What is happening to effective Lf as perf efficiency increases?

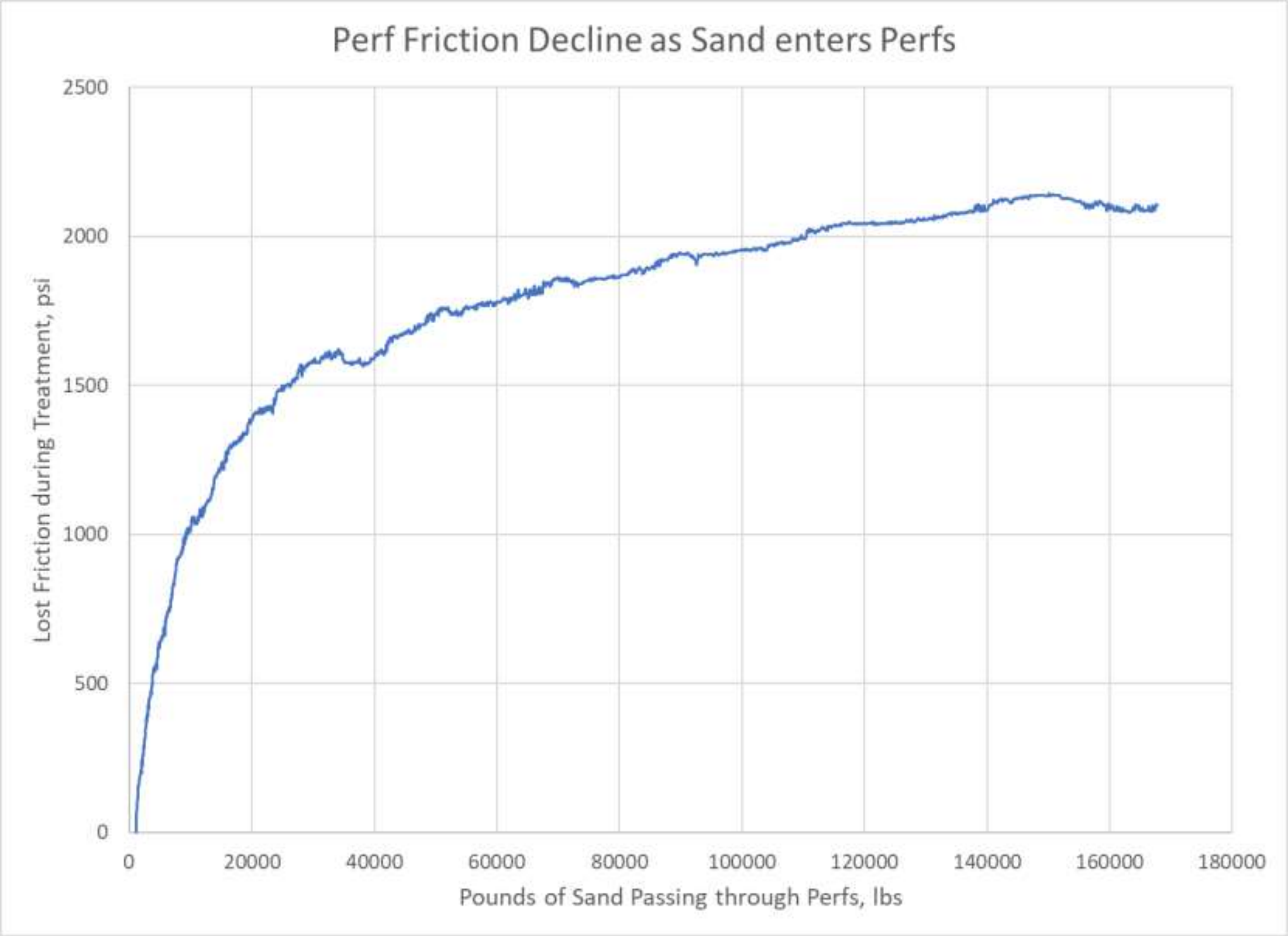
At what "per frac" rate can we place a slickwater job?

"DAS/DTS fiber data indicated one or two dominate fractures per (stage), and this behavior was mimicked by the fracture modeling …" – American Oil & Gas Reporter Article – Baree, Miskimins, Deeg, Haustveit & Wheaton – (Nov. 2018)


Stage 1
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
STP, psi
120
100
80
60
40
20
0
Rate, PPG*10, lbs/gal
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
Time, Seconds
STP
Rate
PPG*10
BH PPG*10
InLine PPG*10



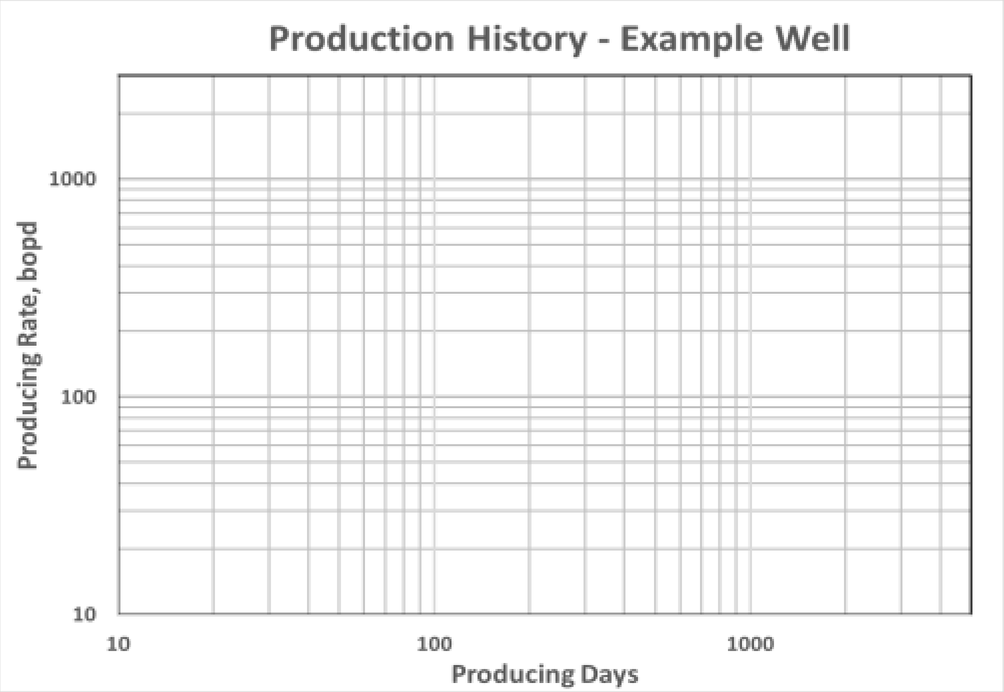
- The STP declines by over 2000 psi during the treatment
- This decline begins as soon as sand starts entering the perfs
- Final perf friction is significantly less than the initial perf friction
- This is due to erosion of the perforations



- About 1500 psi of friction is lost with the first 20klbs of sand passing through the perfs
- Significant erosion of the perforations is occurring as sand enters the perfs

Month 0

Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

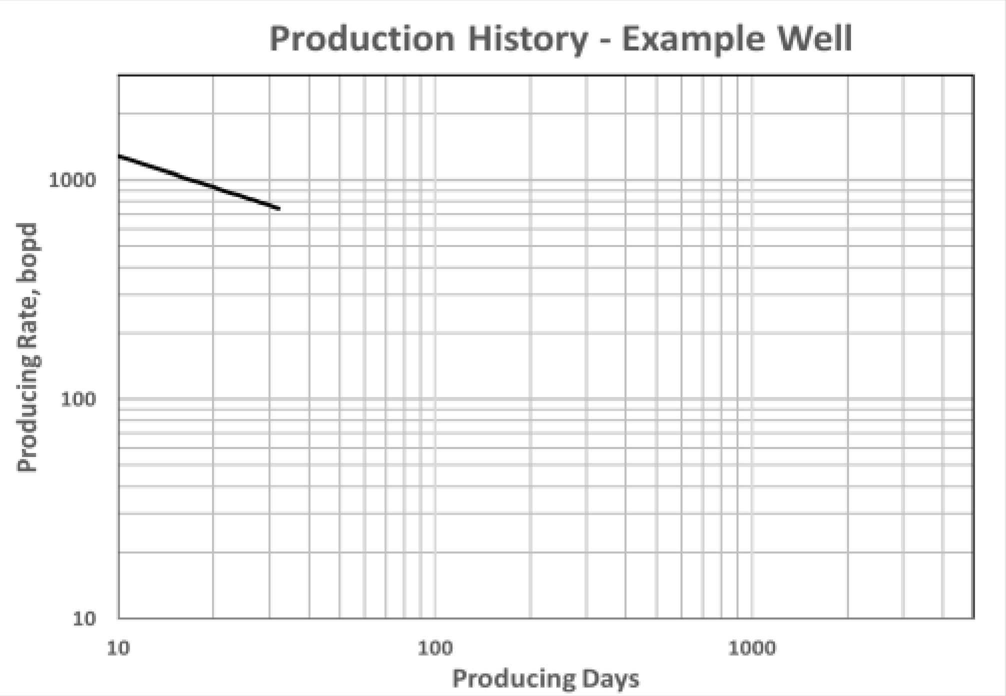


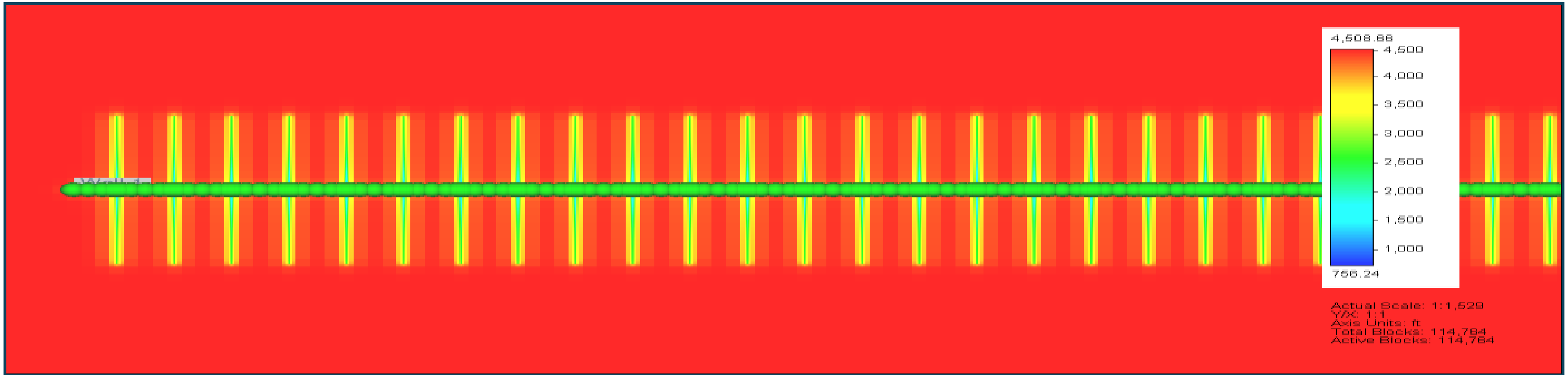
Net Pay = 78 feet
Porosity = 5.3%
Permeability = 250 nD
Sw = 15%
Bo = 2.1
Oil Visc. = 0.18 cps
Pi = 4500 psi
Pwf = 750 psi
Lateral Length = 10,800 feet
Fracture Spacing = 100 feet
Effective Lf = 250 feet

Reservoir Pressure Map

Month 1

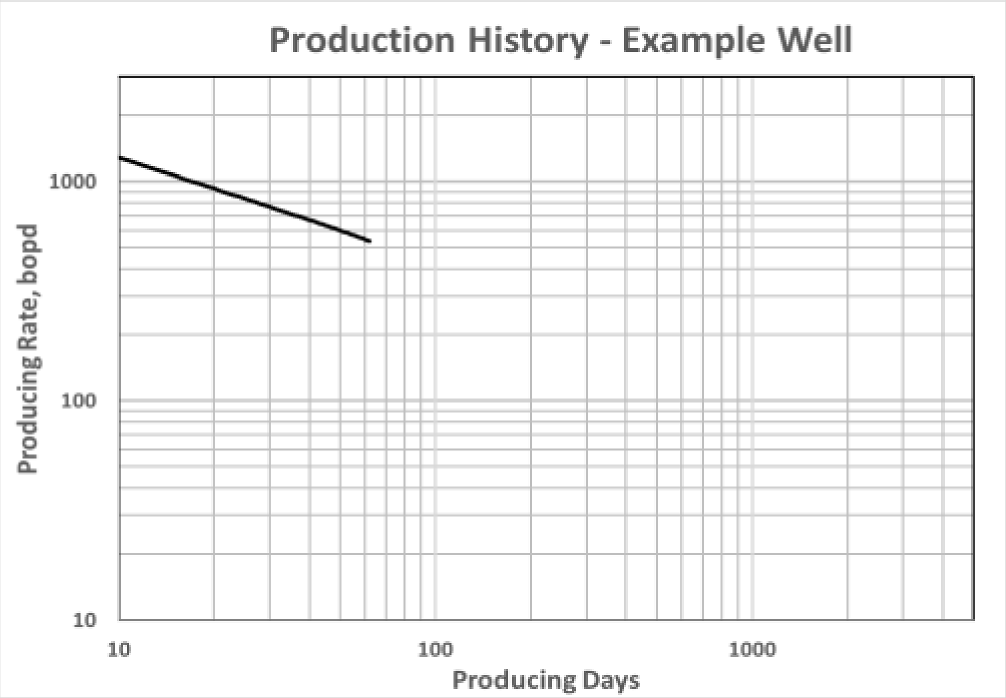
Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

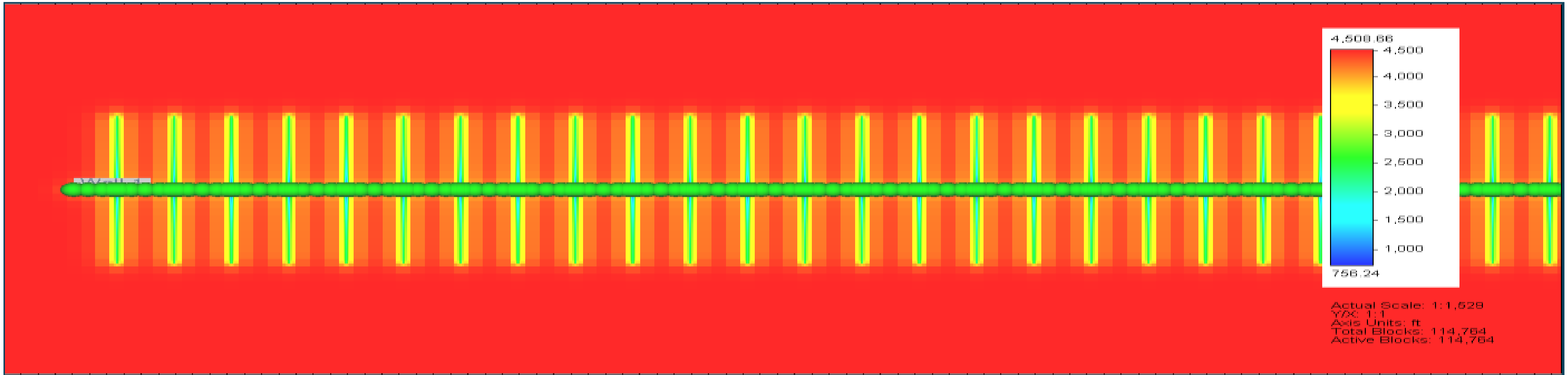




Month 2

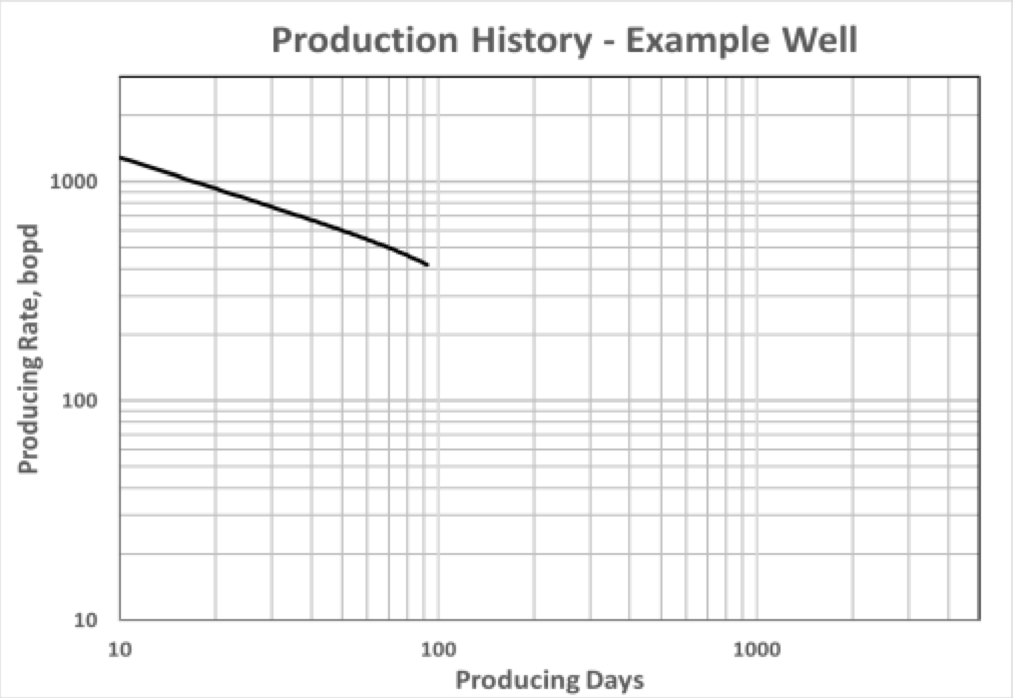
Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

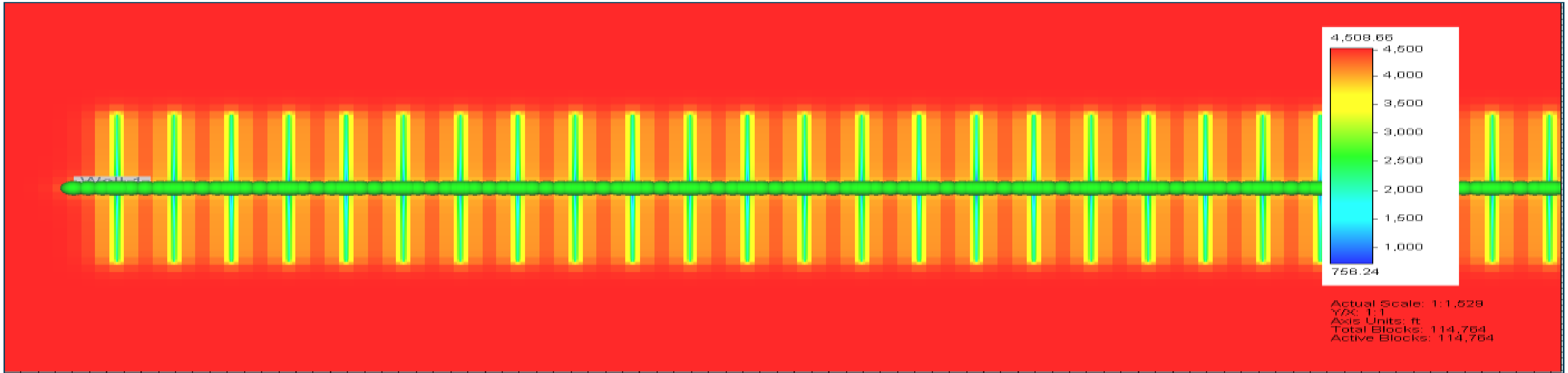




Month 3

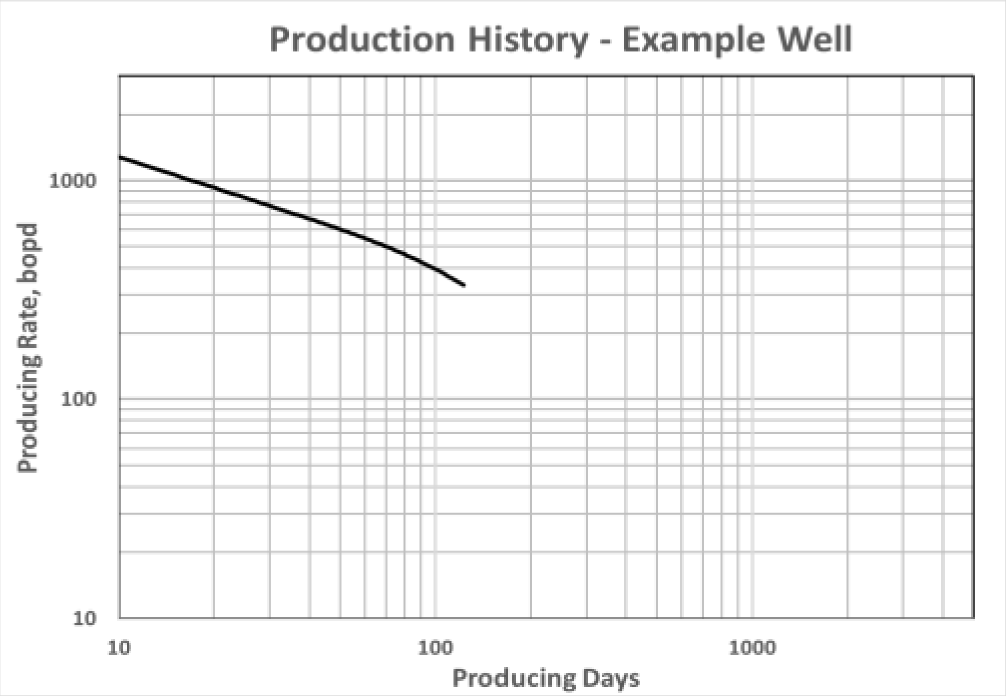
Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

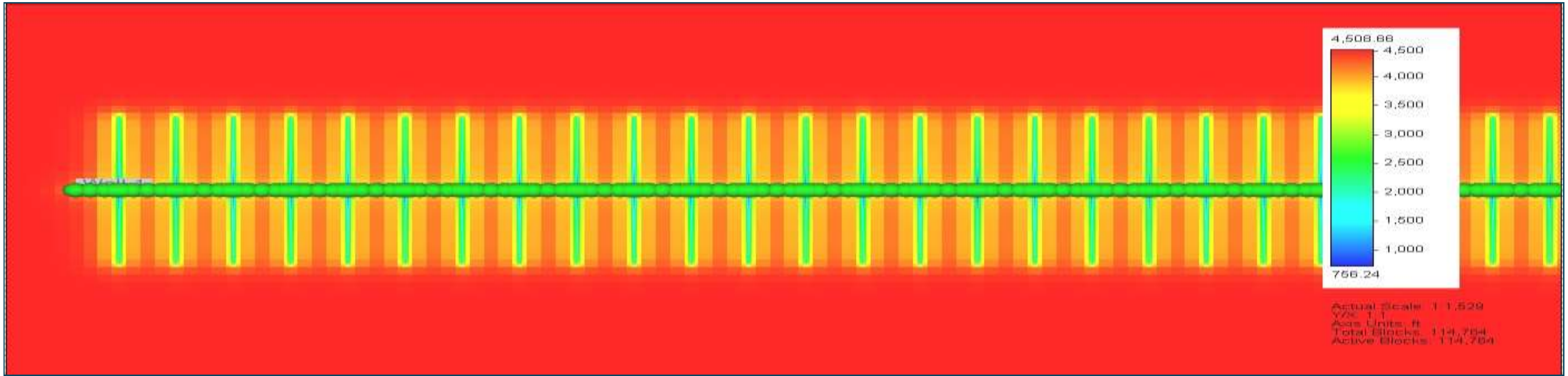




Month 4

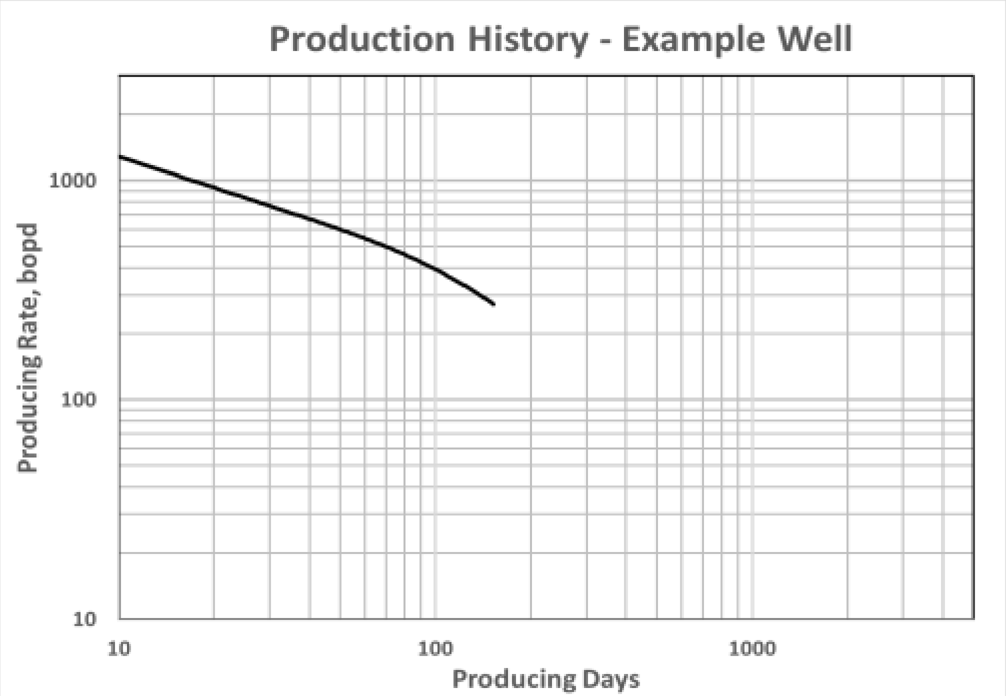
Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days

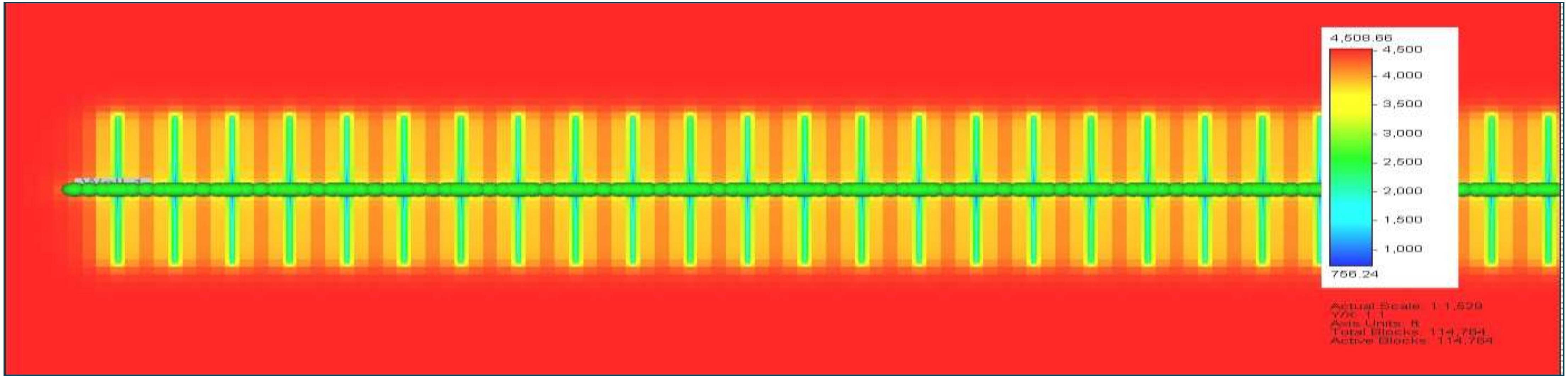




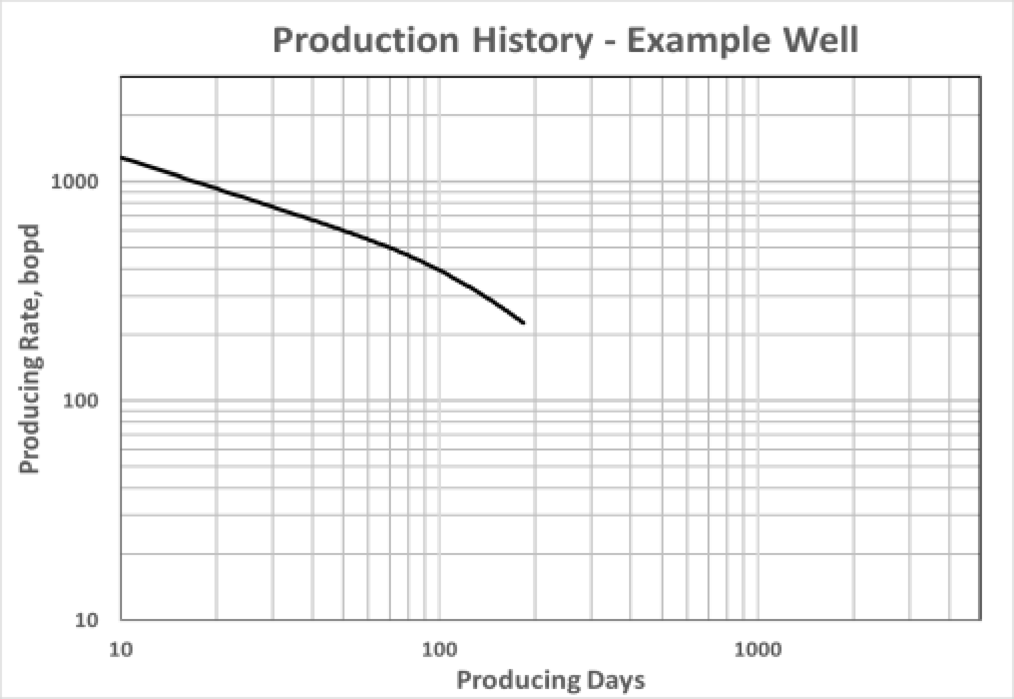
Month 5

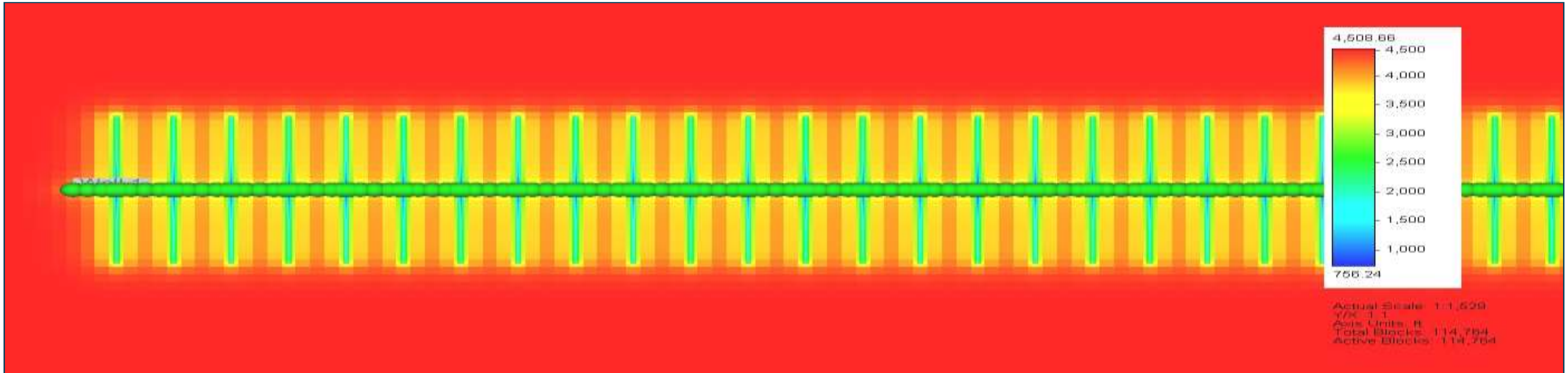
Calculating Time to the End of Linear Flow		
k	250	nD
Porosity	5.3%	
Viscosity	0.18	cps
Co	2.5E-05	psi-1
Cf	4.0E-06	psi-1
Sw	30%	
# of Fracs/Stage	2	
Ct	2.26E-05	psi-1
Stage Length	200	ft
Time End LF	108.3	days



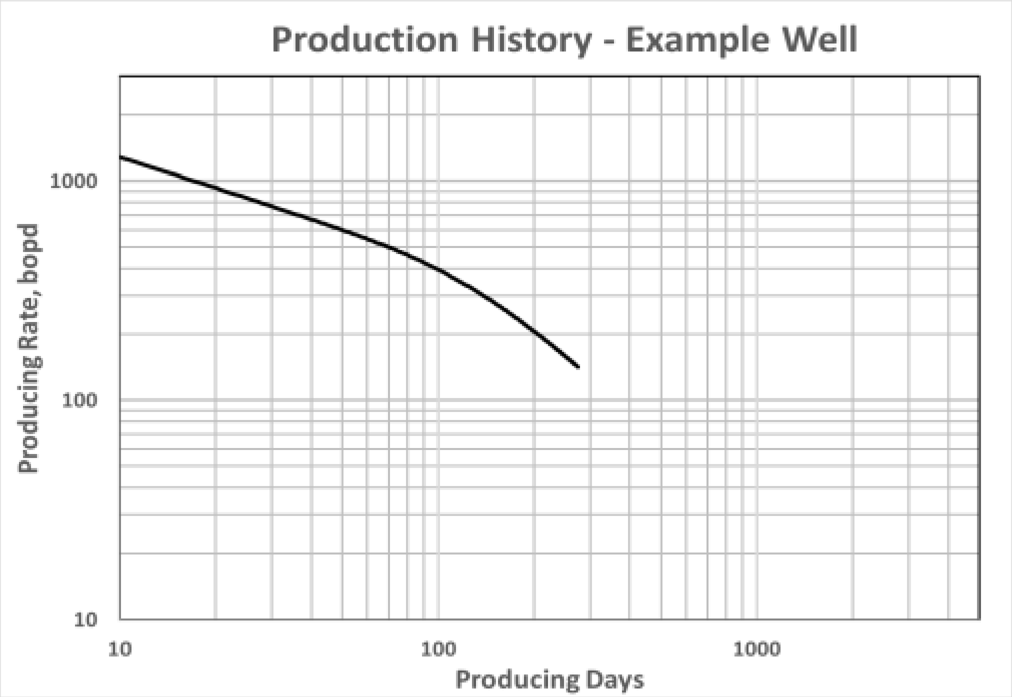


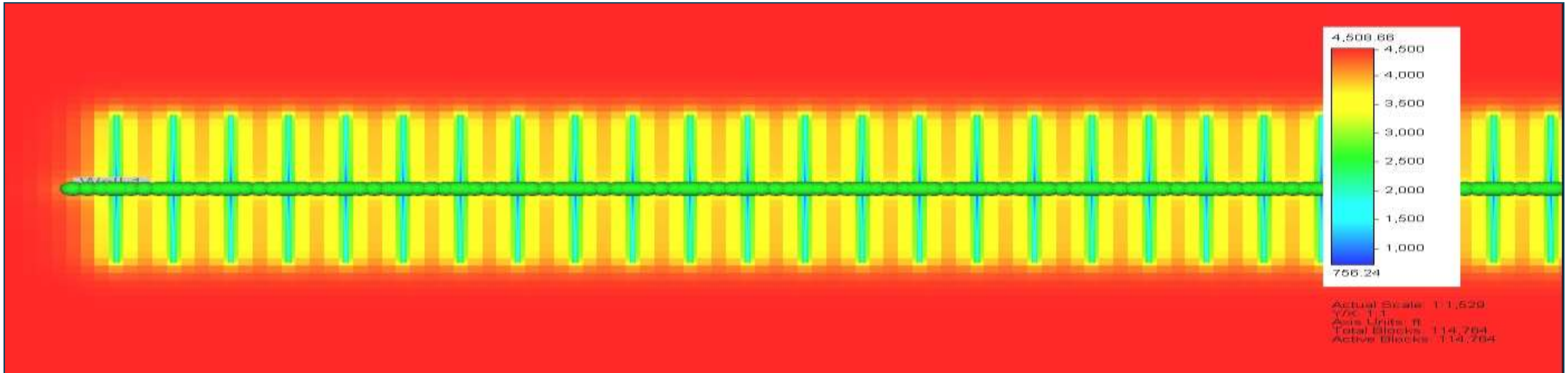
Month 6


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days

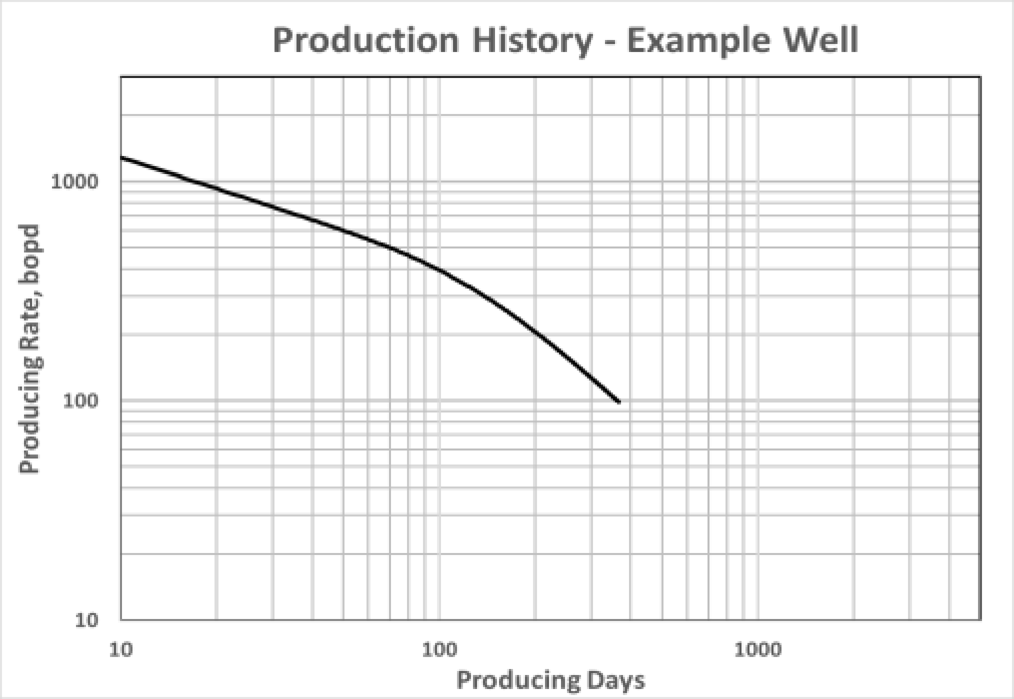

4,508.66
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
756.24

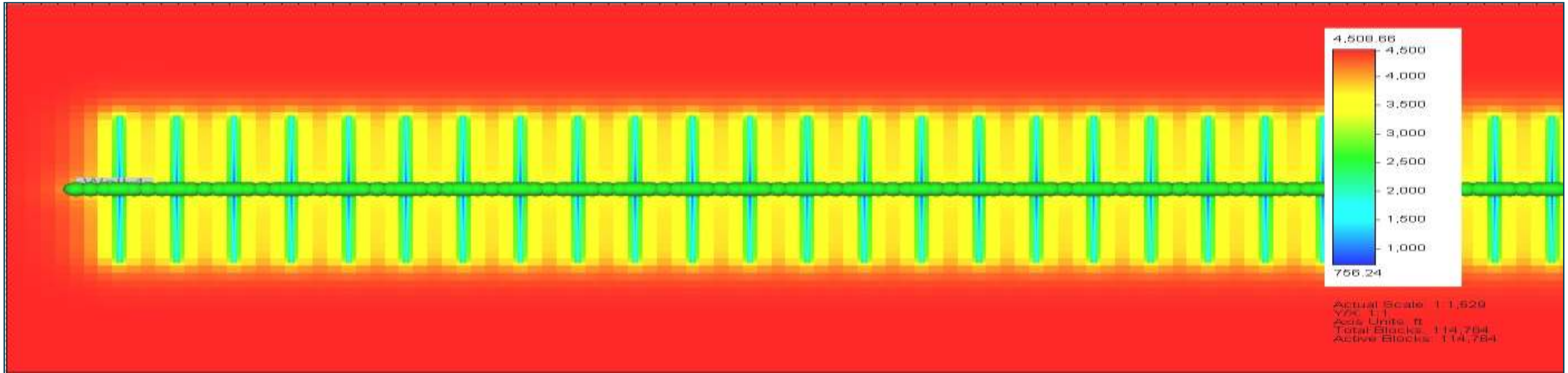
Month 9


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days

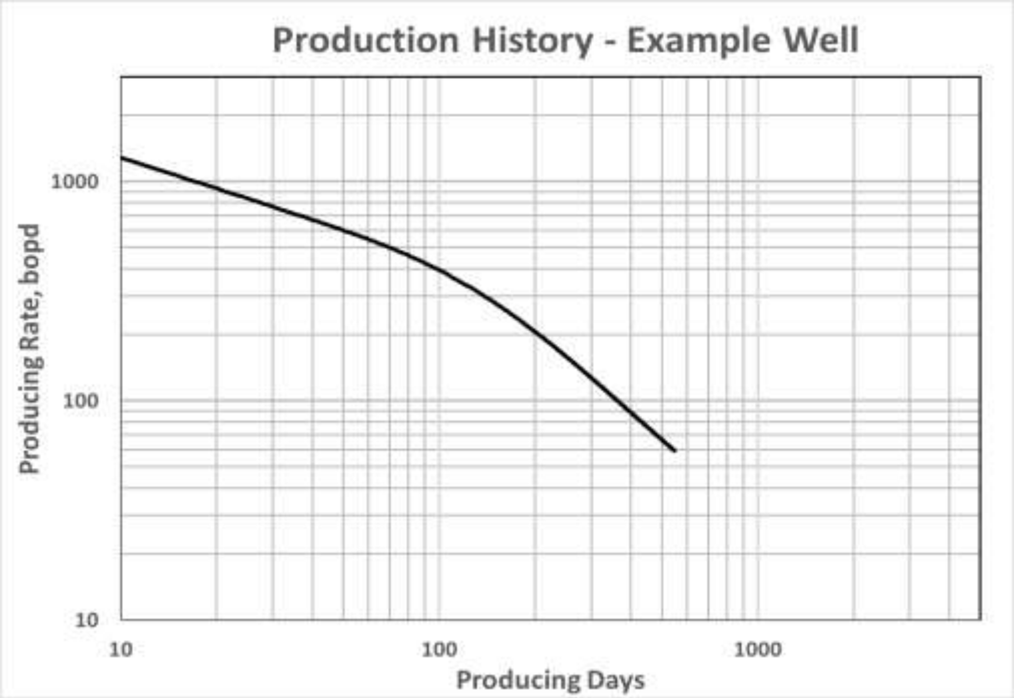

4,508.66
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
756.24

Month 12

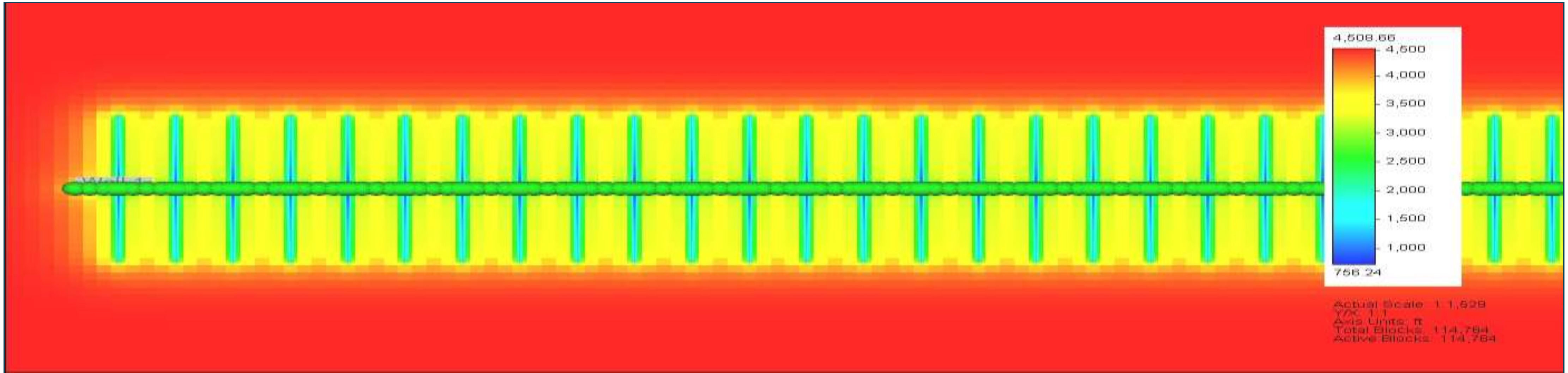

Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days


4,508.66
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
756.24

Month 18



Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days



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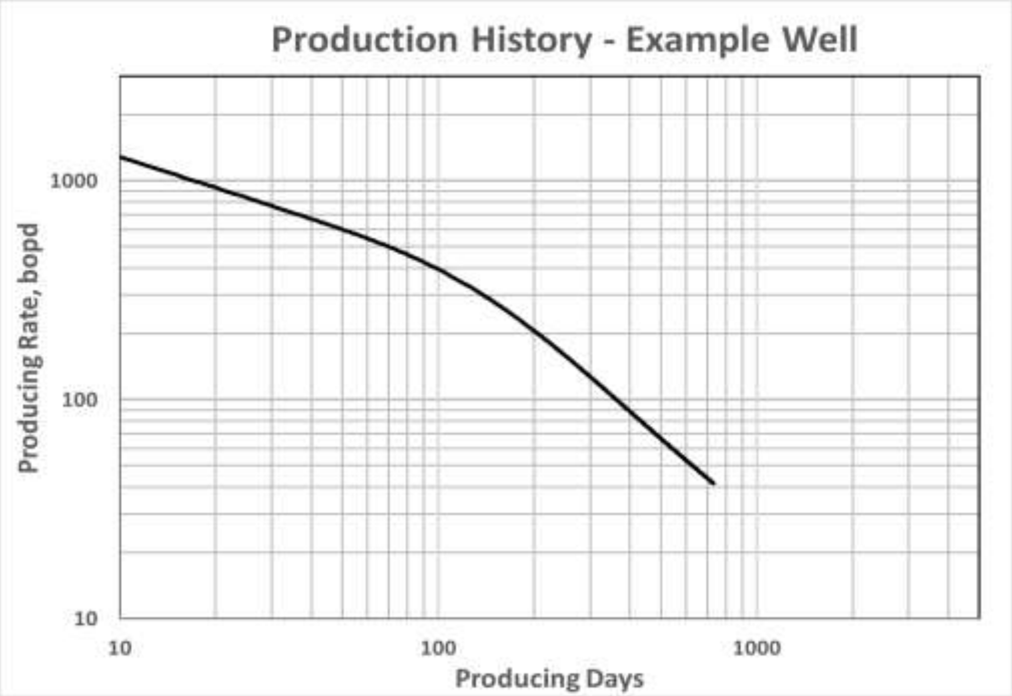
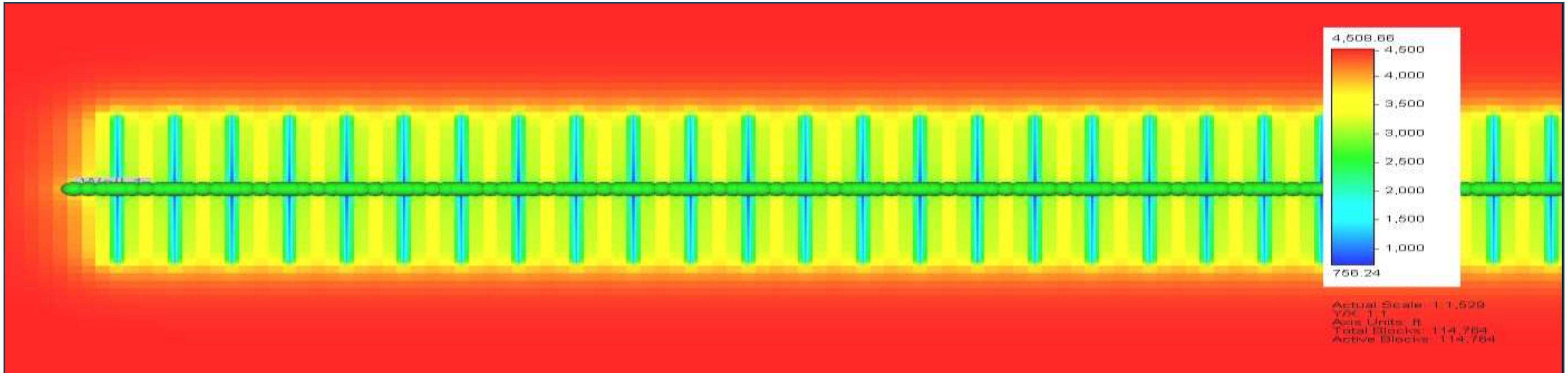
4,000
3,500
3,000
2,500
2,000
1,500
1,000
758.24

Month 24


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days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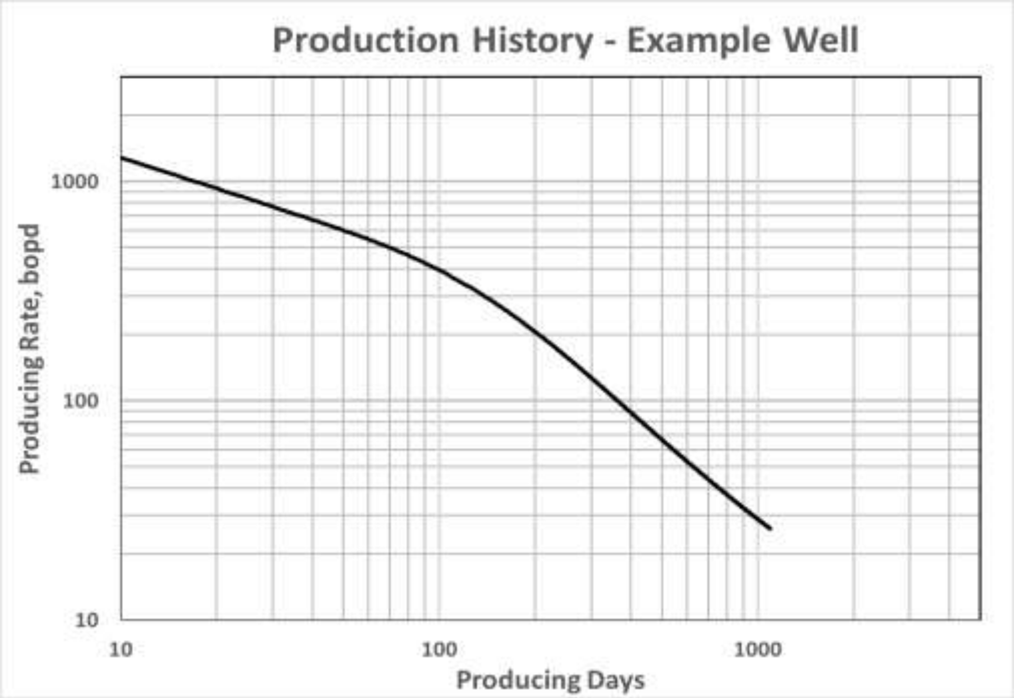
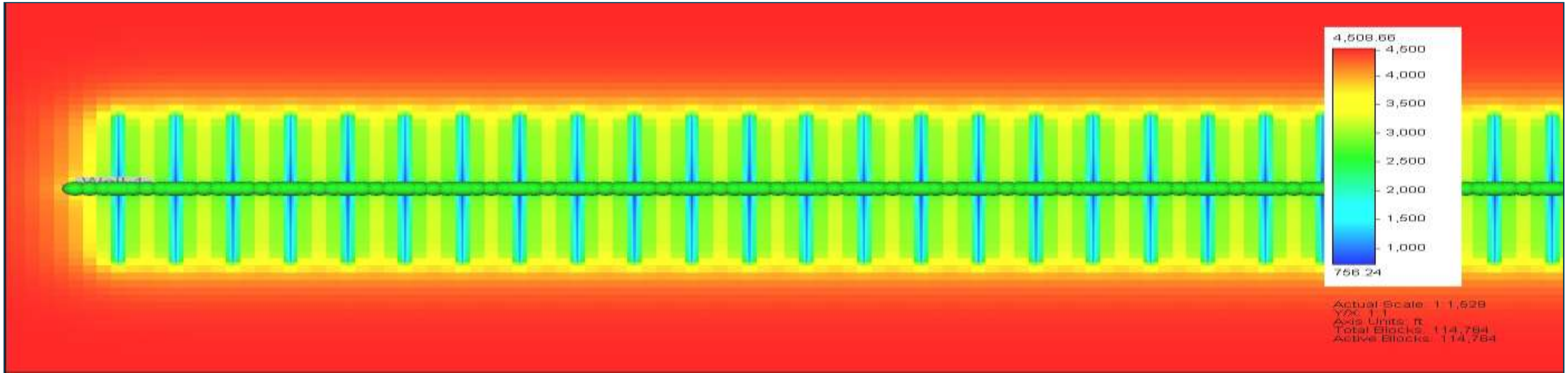
2,500
2,000
1,500
1,000

Month 36


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days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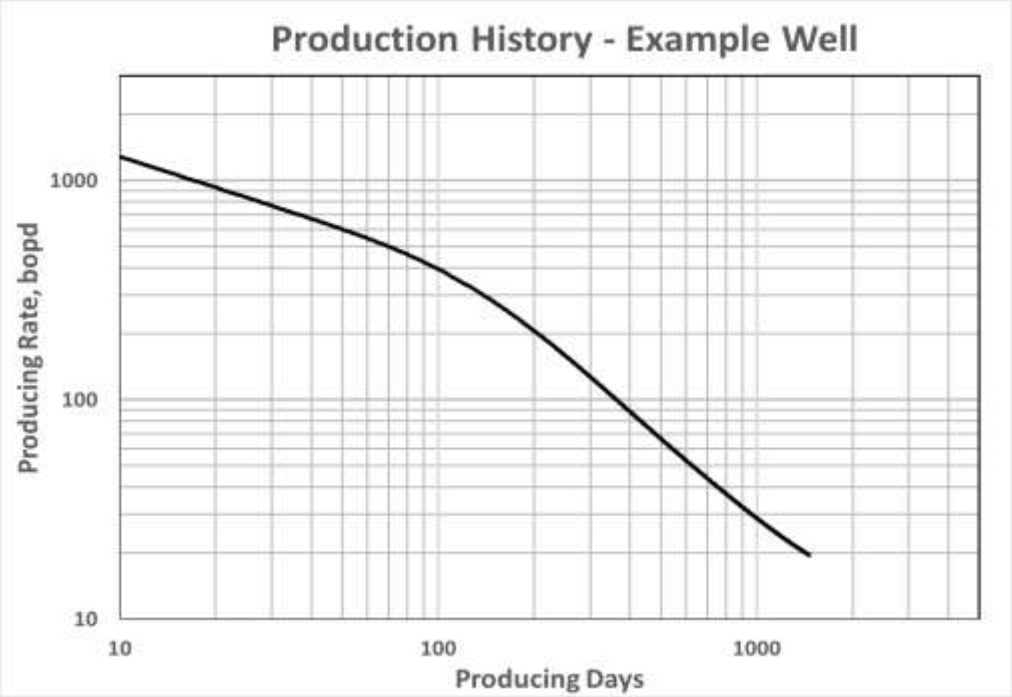
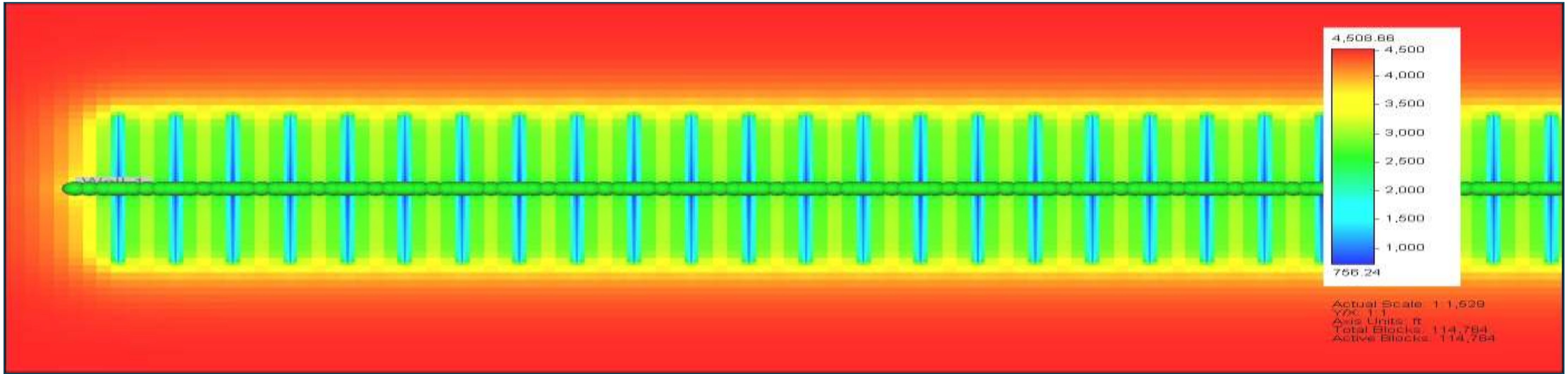
4,000
3,500
3,000
2,500
2,000
1,500
1,000
758.24
Actual Scale: 1:1,628
Y/X: 1:1
Axis Units: ft
Total Blocks: 114,784
Active Blocks: 114,784

Month 48


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days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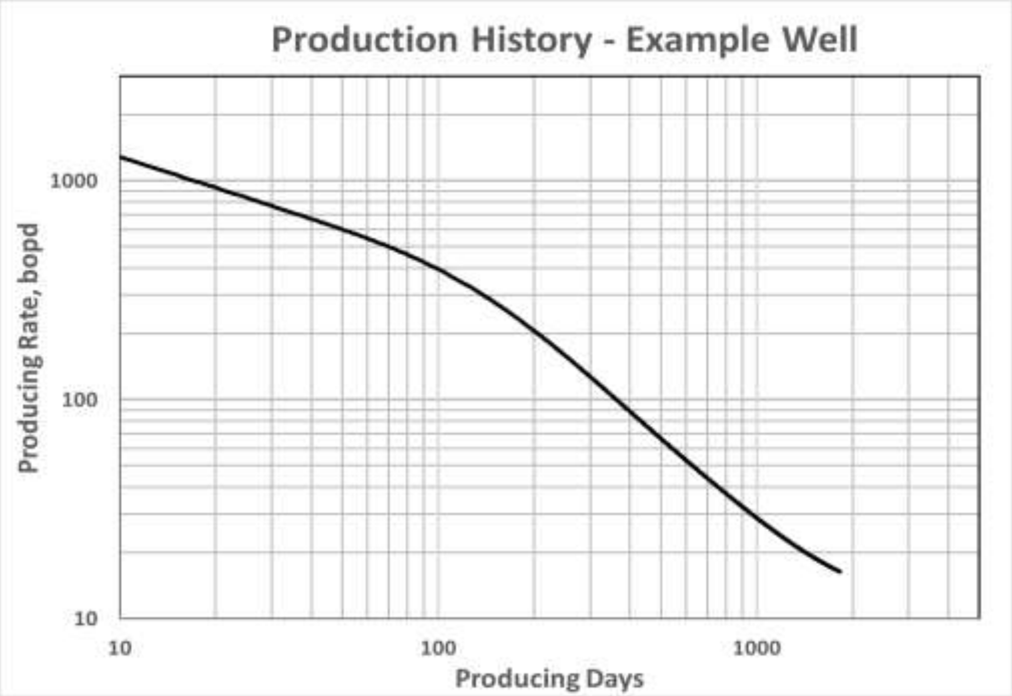
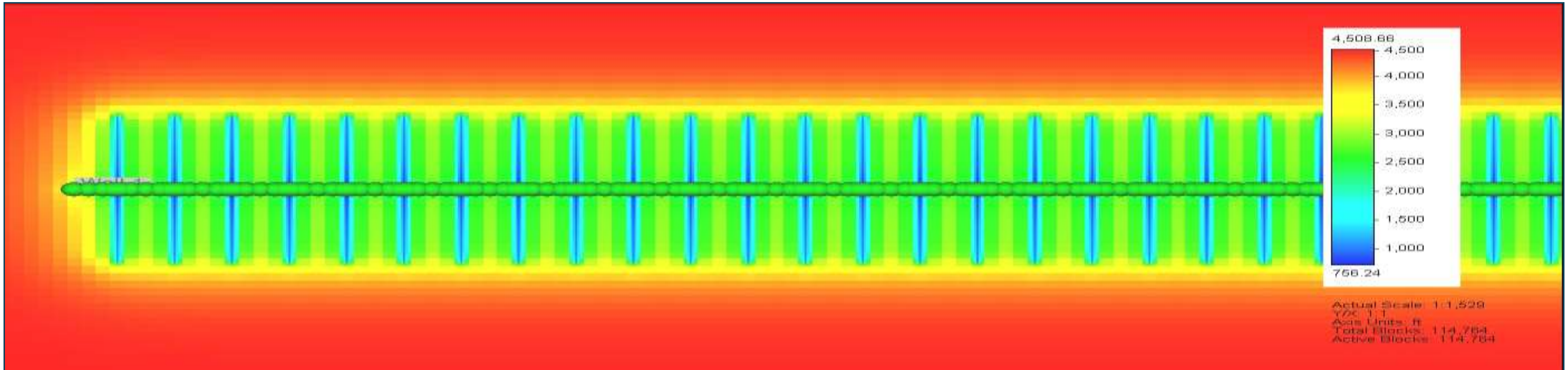
2,000
1,500
1,000
756.24

Month 60


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days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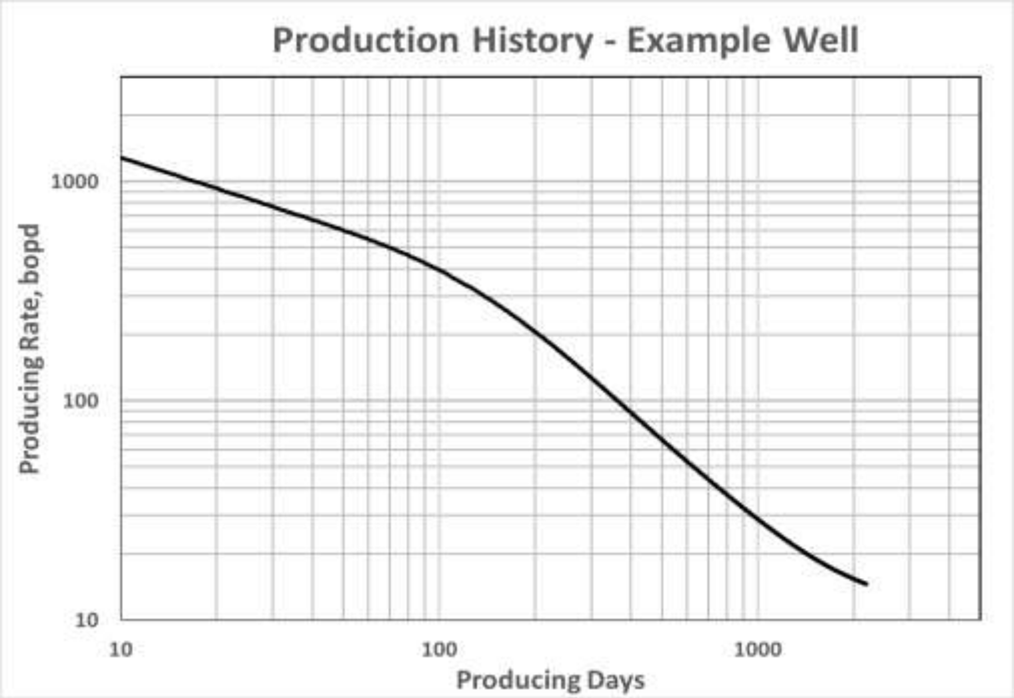
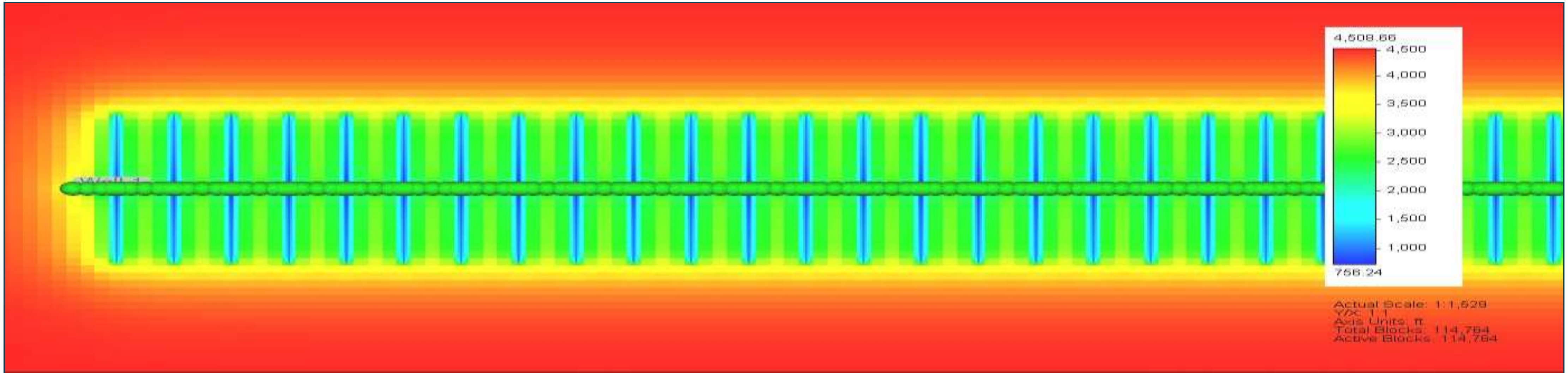
2,500
2,000
1,500
1,000

Month 72


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days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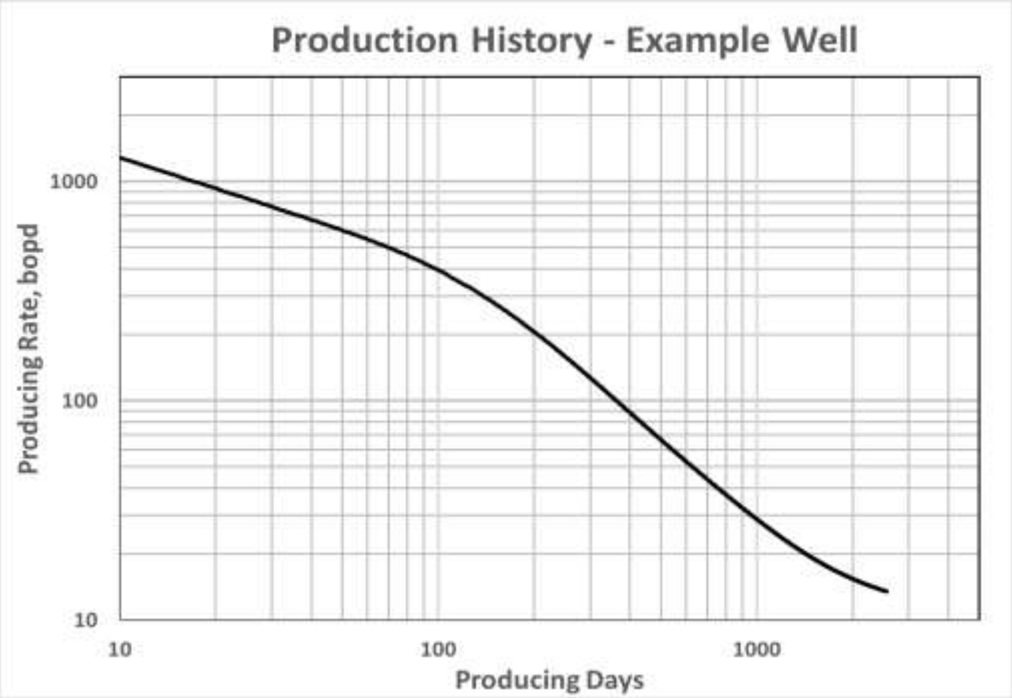
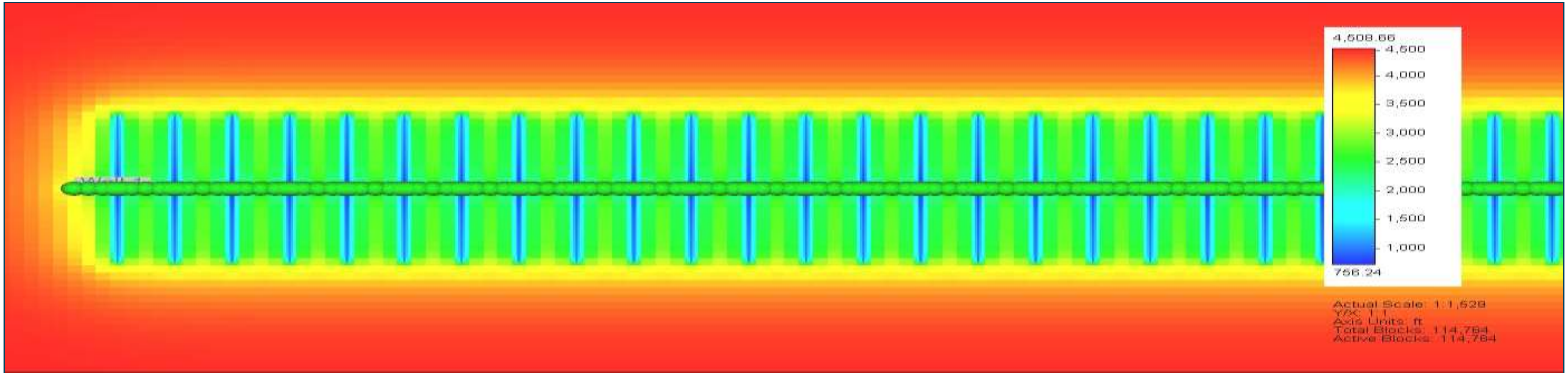
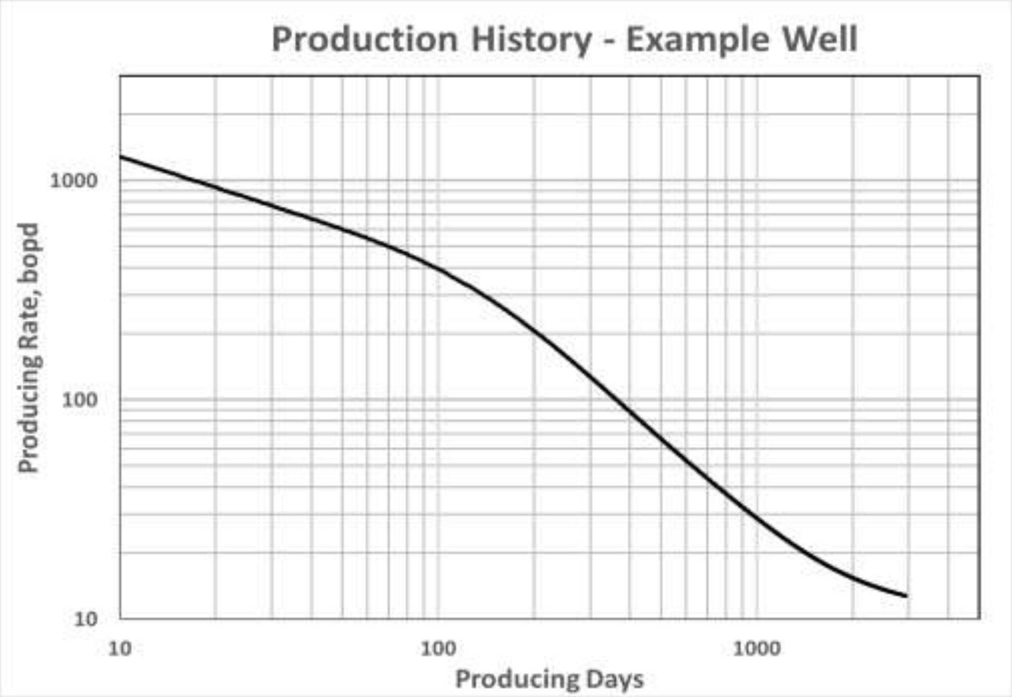
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
758.24
Actual Scale: 1:1,529
Axis Units: ft
Total Blocks: 114,784
Active Blocks: 114,784

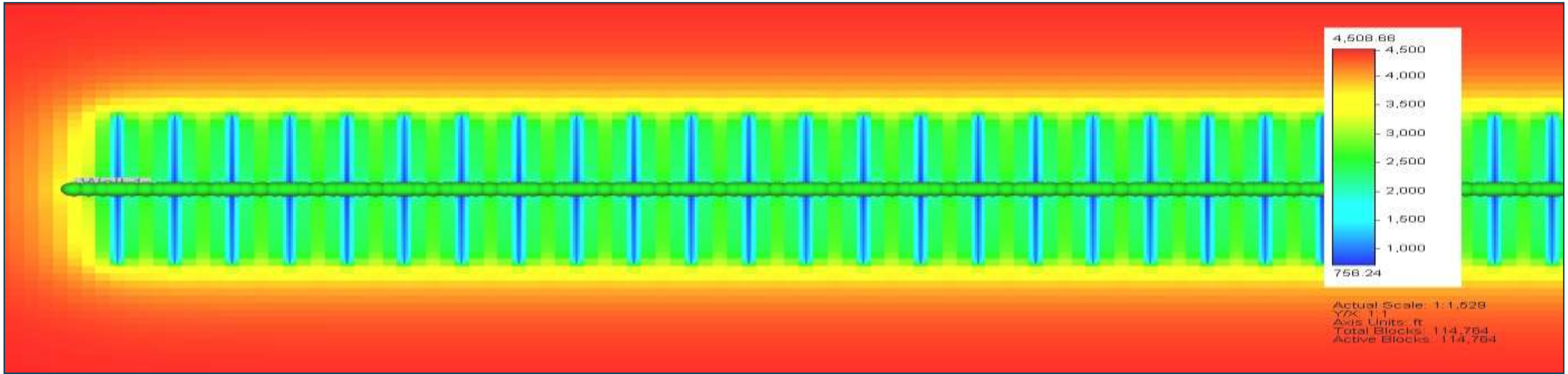
Month 84


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days


4,508.66
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
756.24
Actual Scale: 1:1,529
Y/X: 1:1
Axis Units: ft
Total Blocks: 114,784
Active Blocks: 114,784

Month 96


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days


4,508.66
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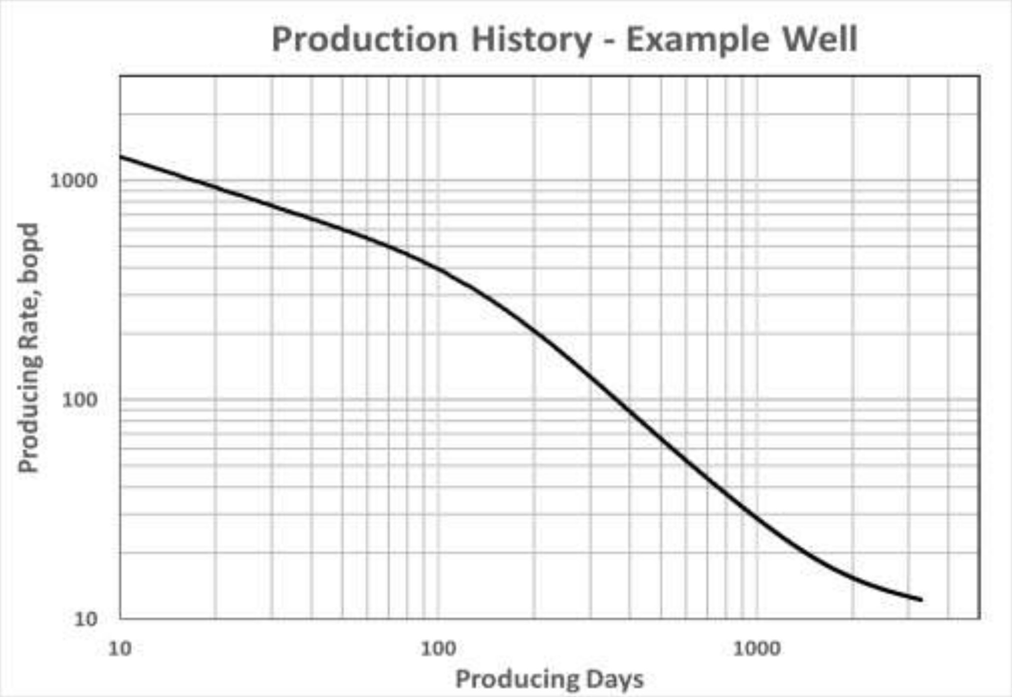
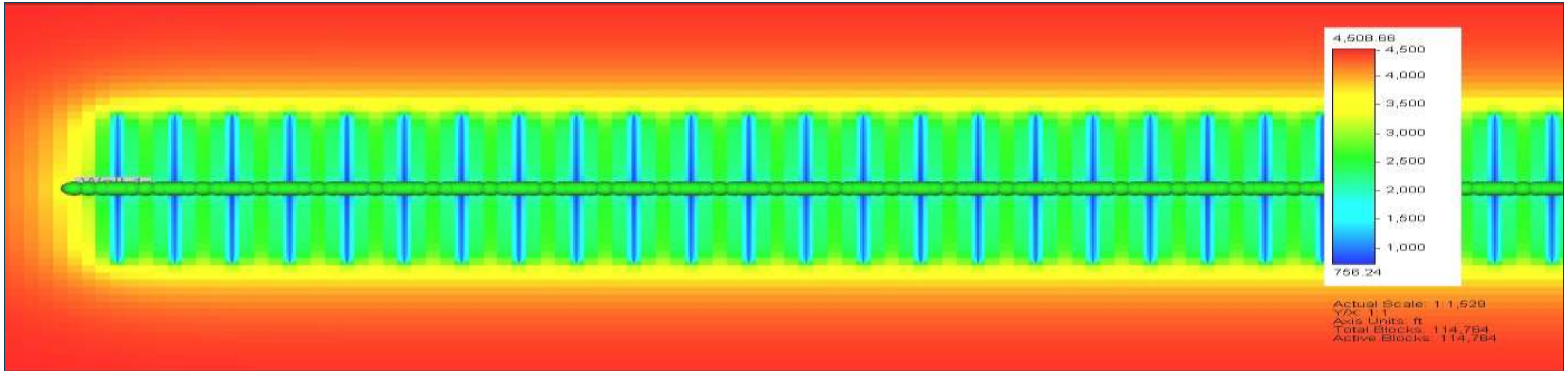
4,000
3,500
3,000
2,500
2,000
1,500
1,000
758.24
Actual Scale: 1:1,628
Y/X: 1:1
Axis Units: ft
Total Blocks: 114,784
Active Blocks: 114,784

Month 108

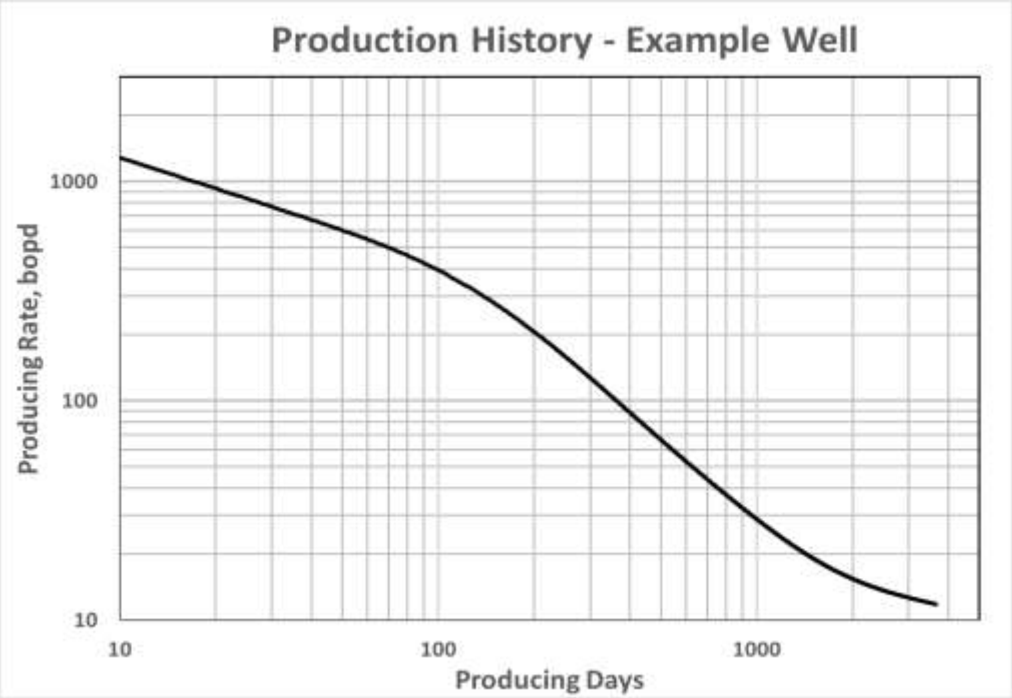


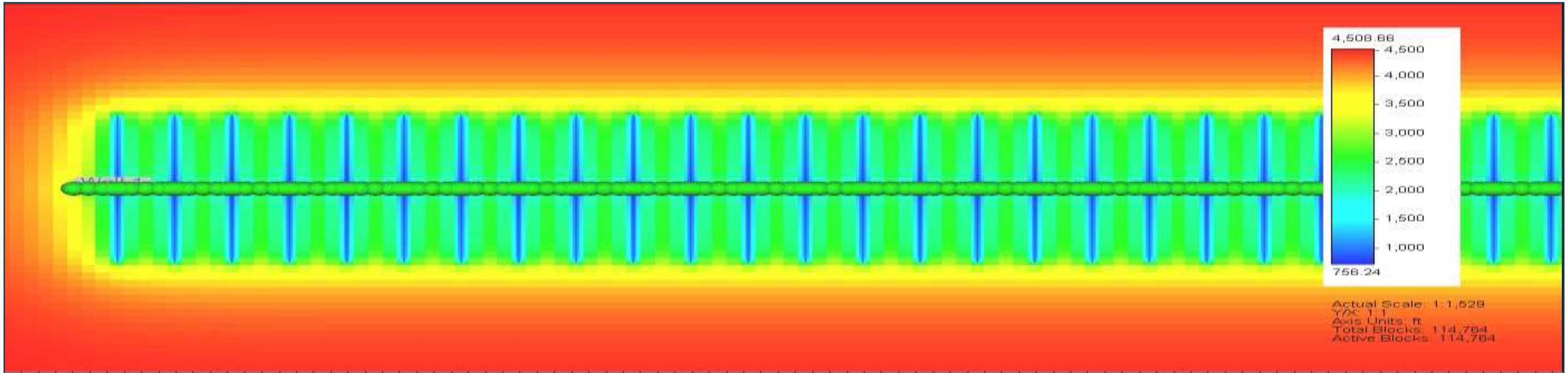
Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days



4,508.66
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
756.24
Actual Scale: 1:1,528
Y/X: 1:1
Axis Units: ft
Total Blocks: 114,784
Active Blocks: 114,784

Month 120


Production History - Example Well
Producing Rate, bopd
1000
100
10
10
100
1000
Producing Days


4,508.66
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
758.24

Optimizing Unconventional Completion Designs: A New Engineering and Economics Based Approach

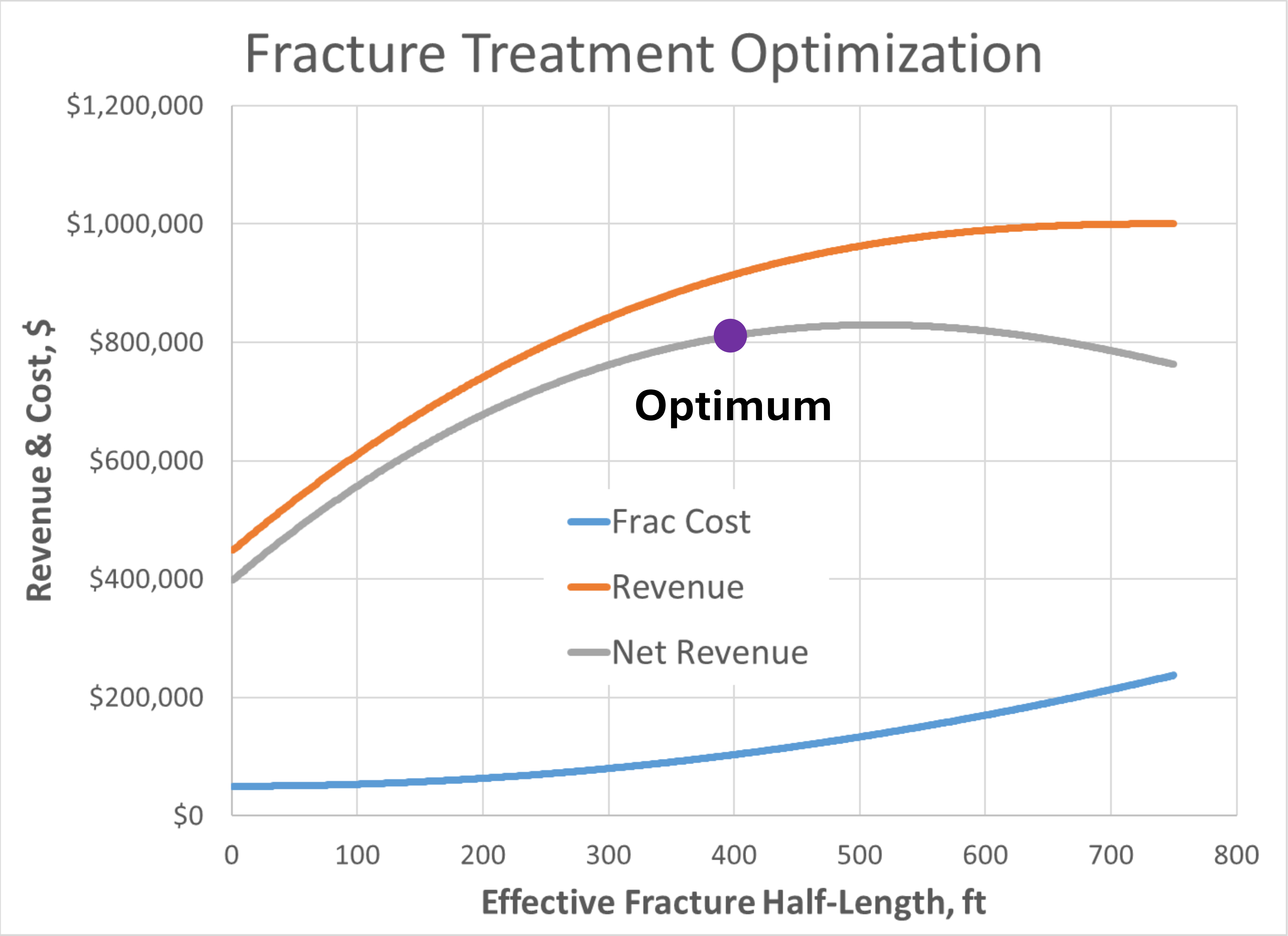
S. Schubarth – SSS LLC

S. Holditch – TAMU

R. Chabaud – SSS LLC

Introduction

- The Process
- The Model
- Production decline behavior in Hz UR wells
- A Parametric Study
- Real case evaluation
- Conclusions

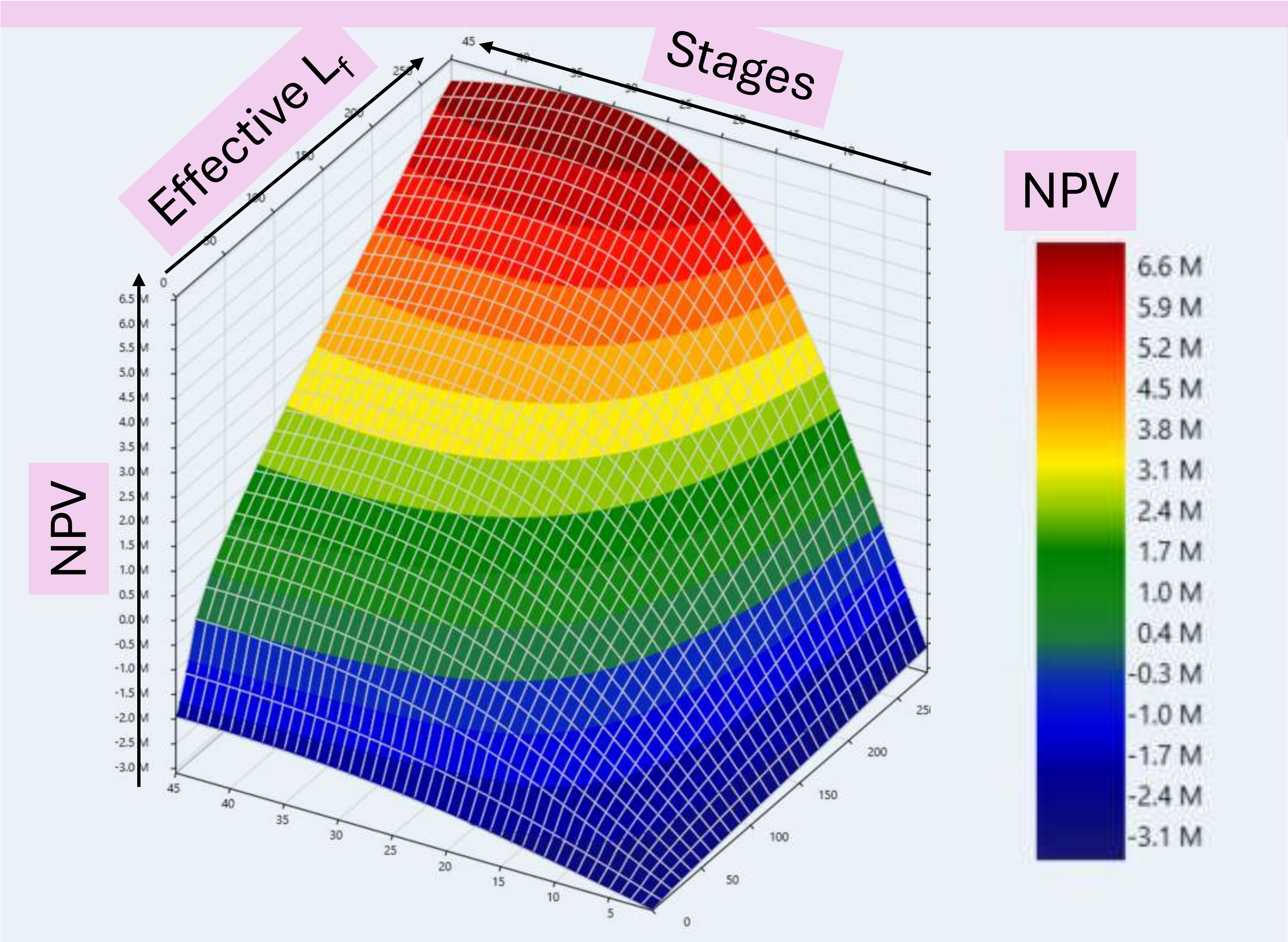


Fracture Treatment Optimization
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
Revenue & Cost, $
0
100
200
300
400
500
600
700
800
Effective Fracture Half-Length, ft
Optimum
Frac Cost
Revenue
Net Revenue

The Evaluation Process

- Gather Data
  - Production – daily or monthly
  - Reservoir properties (h, ϕ, S_w, P_i, B_o, μ_o, c_o, c_w, c_f)
  - Estimate P_{bhf} (normalize rates if necessary)
- Production history match using analytical model
  - Estimate avg k, avg effective L_f and number of created fractures
- Compare effective L_f to treatment sizes (establish trends)
  - Determine cost to achieve effective L_f
- Model matrix of completion designs and predicted production from model
- Perform Economics using total well cost & commodity pricing selected
- Determine optimum stage count & treatment size for desired lateral length

- Economic outcome is now a surface
- A function of Effective L_f and stage count
- Incremental costs are driven by stage count and treatment size



The Model

- Analytical solution – speed
- Homogeneous, single layer, infinite-acting reservoir
- Planer, transverse fractures of infinite conductivity
  - Rarely more than 2 fracs created per stage
    - Meyerhofer – Production matching w/planer fracs
    - Wu – Modeling of simultaneous multiple fracs in Hz wells
- Constant pressure production

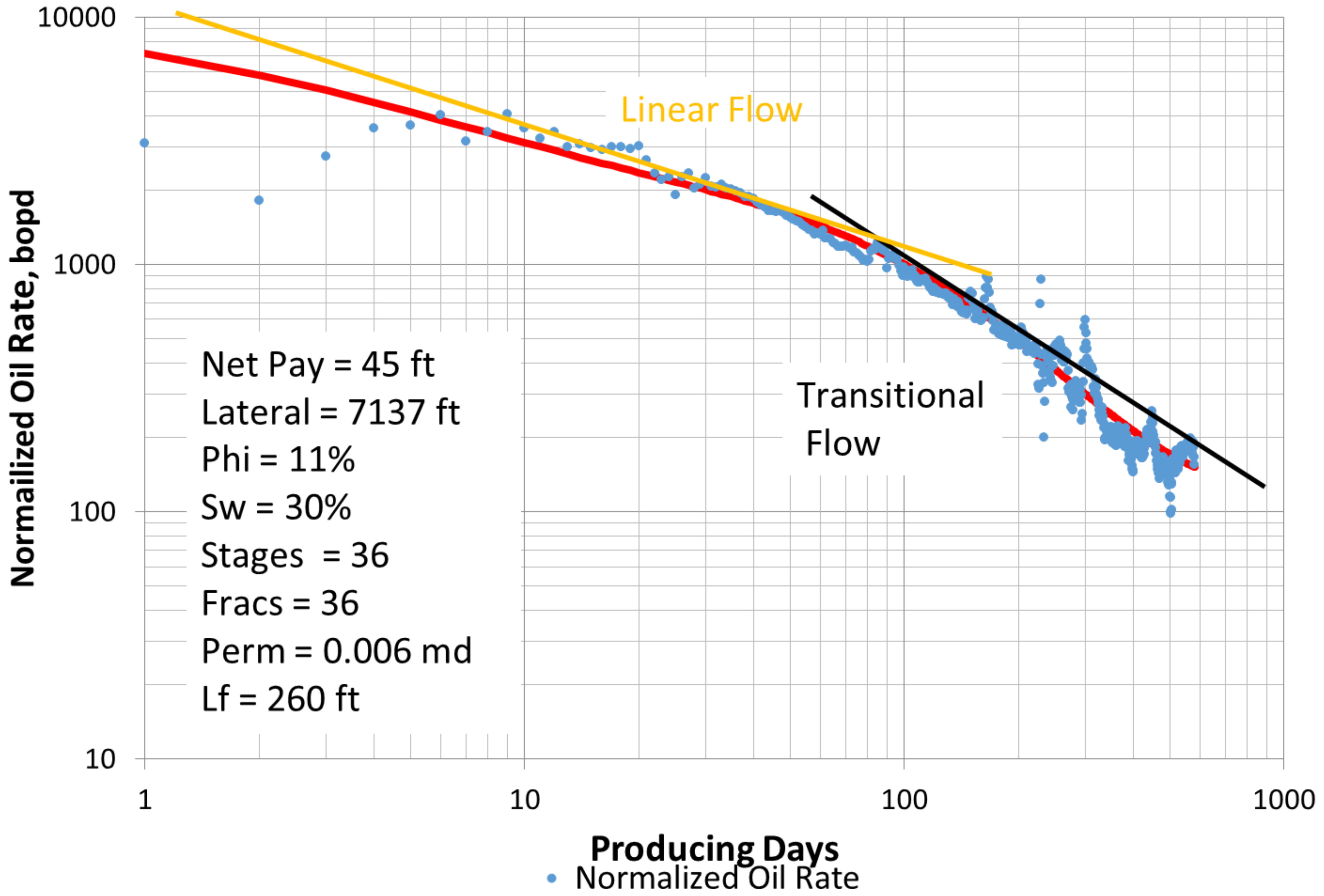
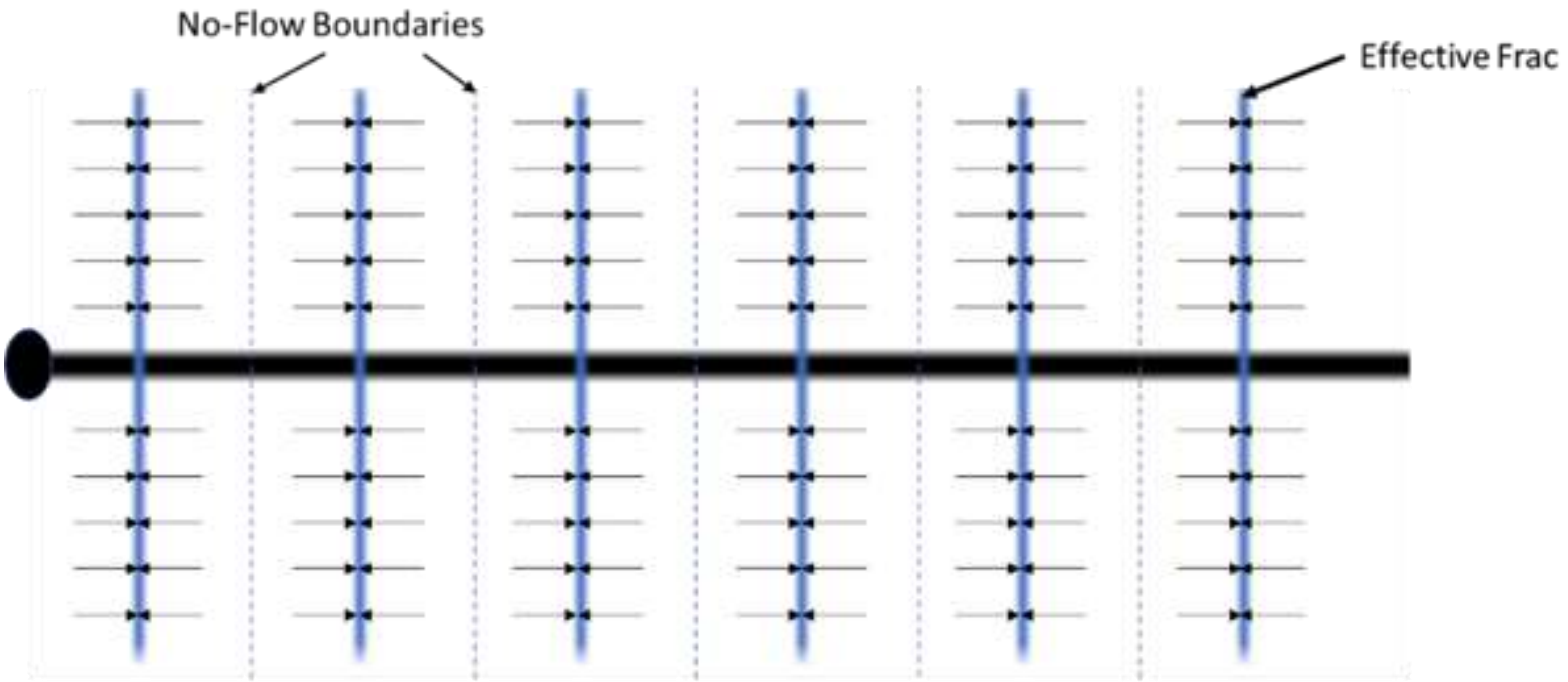


Figure 6a - Example of Production Behavior - West Texas Bone Springs Well 1



$$Early\ Time\ Productivity \approx A\sqrt{k}$$

Where:
A = Effective Fracture Face Area
k = formation permeability

Figure 5a – Example of Early-time Flow Behavior

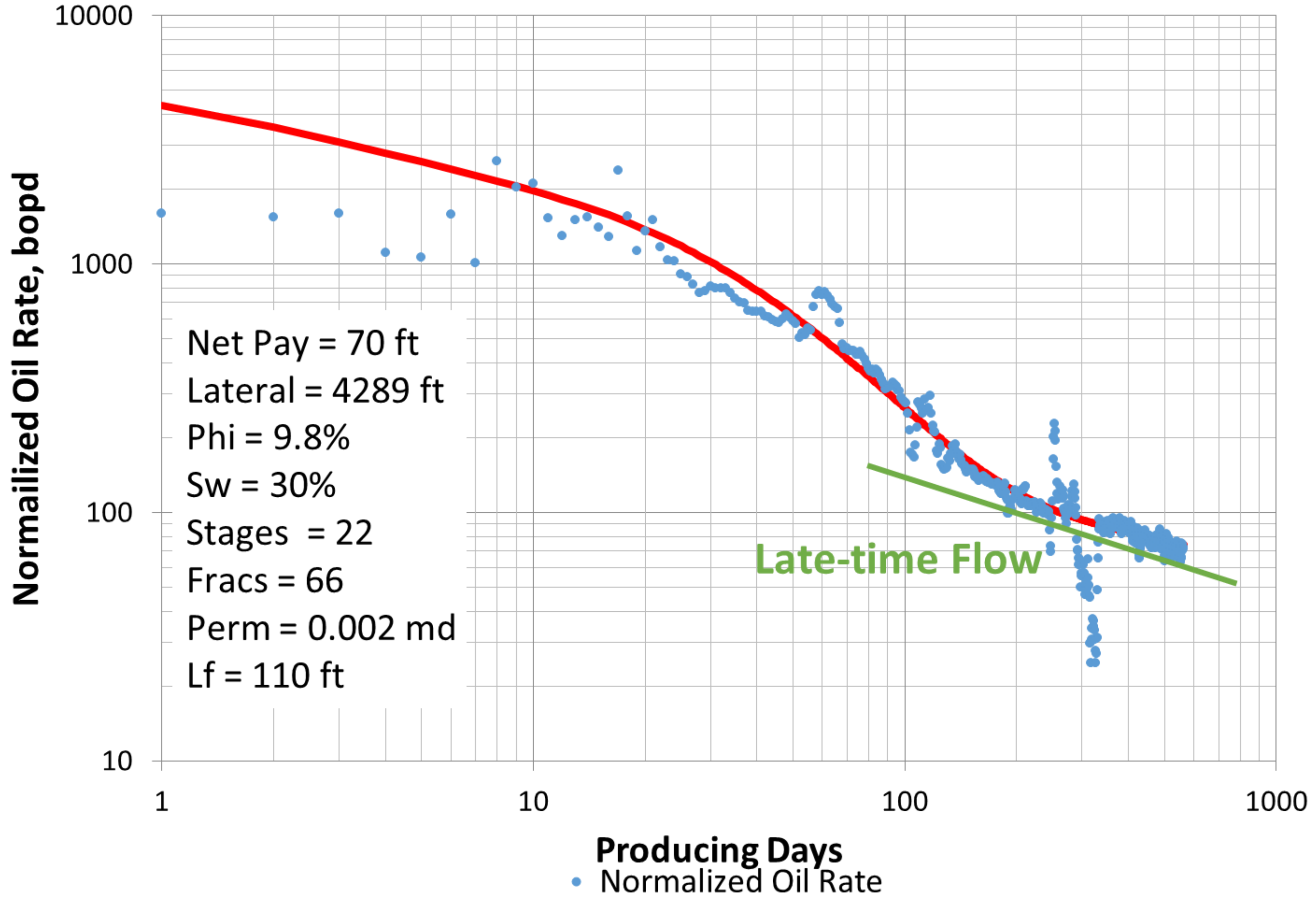
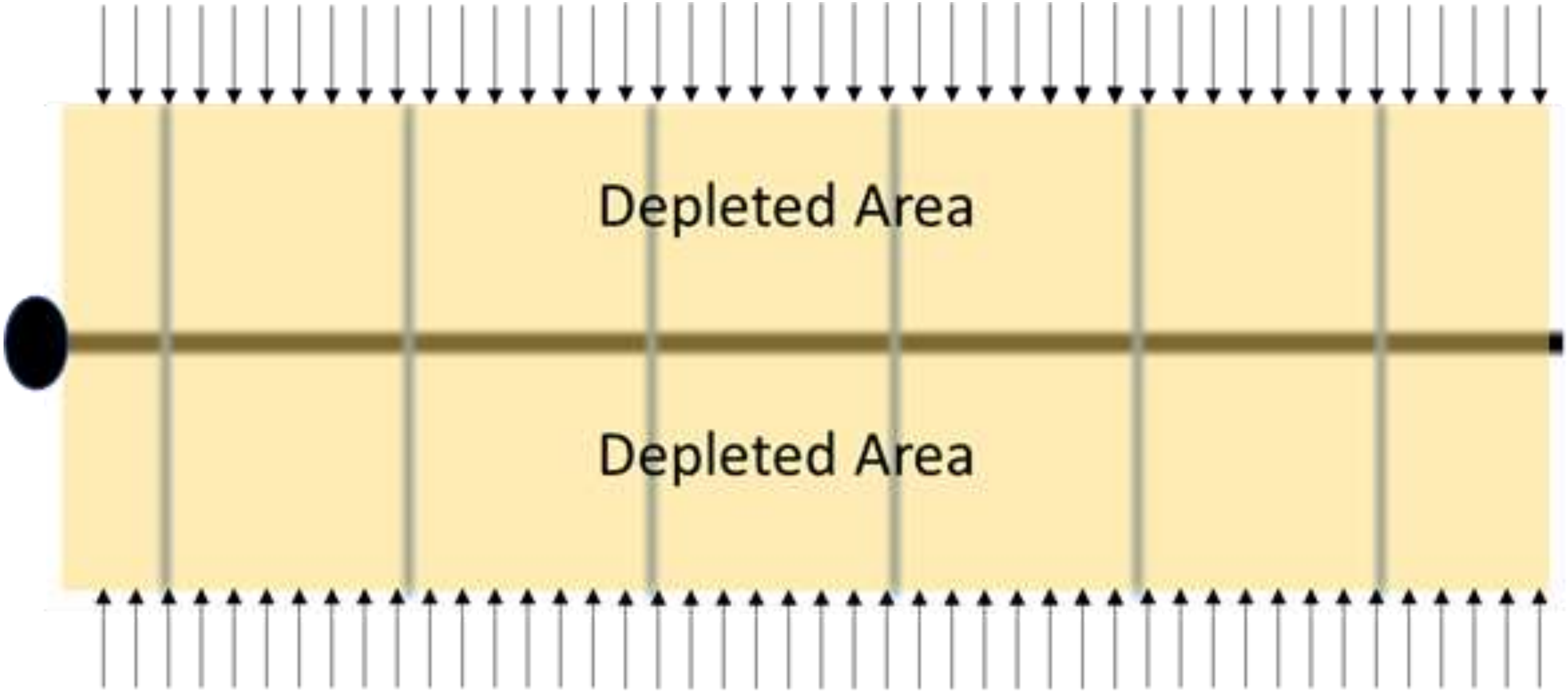


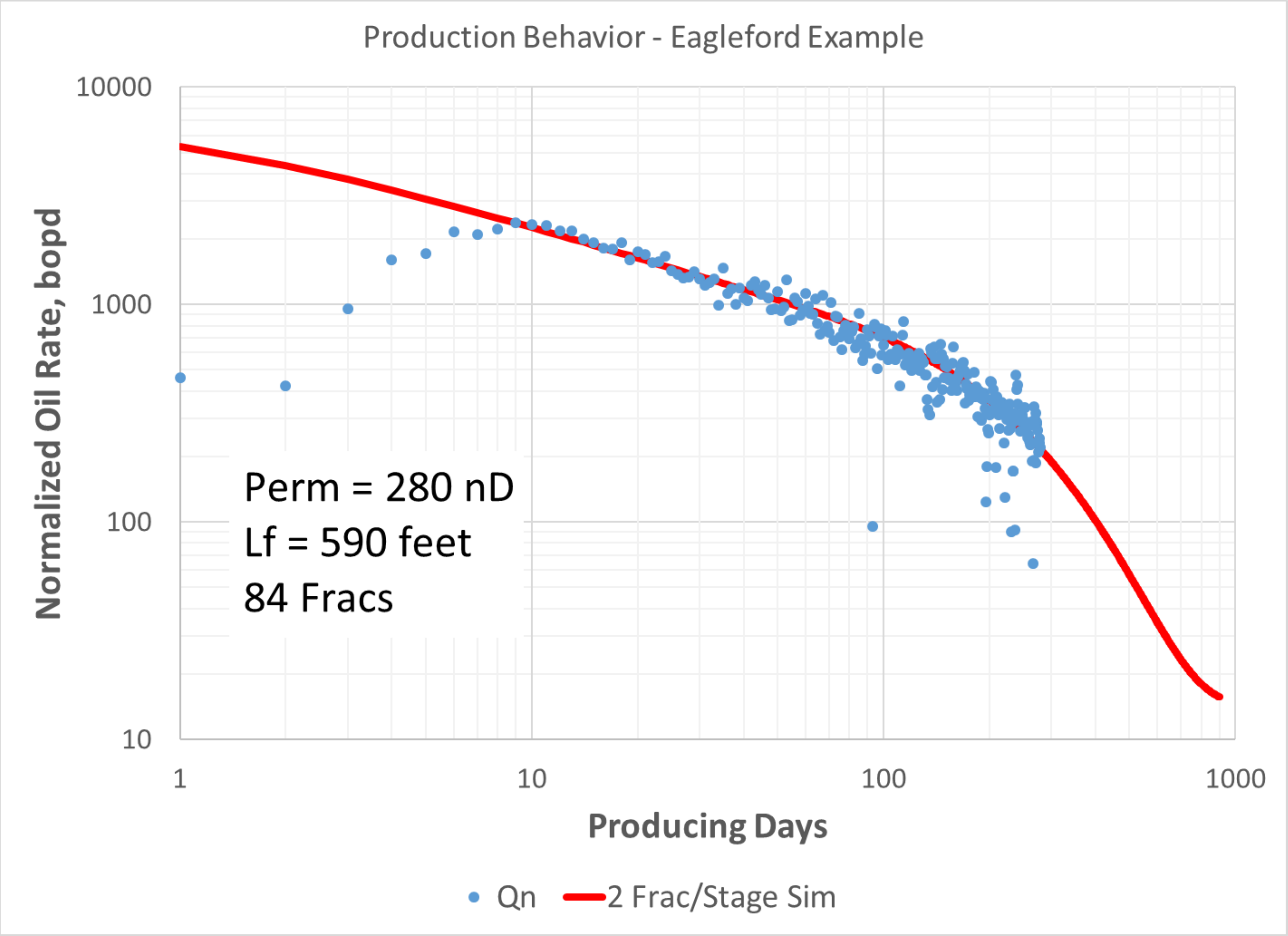
Figure 6b - Example of Production Behavior - West Texas Bone Springs Well 2



$$Late\ Time\ Productivity \approx f(k)$$

Where:
k = formation permeability

Figure 5b – Example of Late-time Flow Behavior


Production Behavior - Eagleford Example
Normalized Oil Rate, bopd
10000
1000
100
10
1
10
100
1000
Producing Days
Perm = 280 nD
Lf = 590 feet
84 Fracs
Qn
2 Frac/Stage Sim

Parametric Study

- This study will show the effect of reservoir permeability on optimum stage count

Table 1
Parametric Study
Reservoir & Production Properties

Net Pay =	100	feet
Porosity =	10%	
Sw =	30%	
Lf =	150	feet
Pi =	5000	psi
Pwf =	750	psi
Bo =	1.2	RB/STB
Oil Viscosity =	0.5	cps
Lateral Length =	7500	feet
Oil Net Value =	50	$/bbl
Stage Cost =	50,000	$
Fixed Well Cost =	2,500,000	$

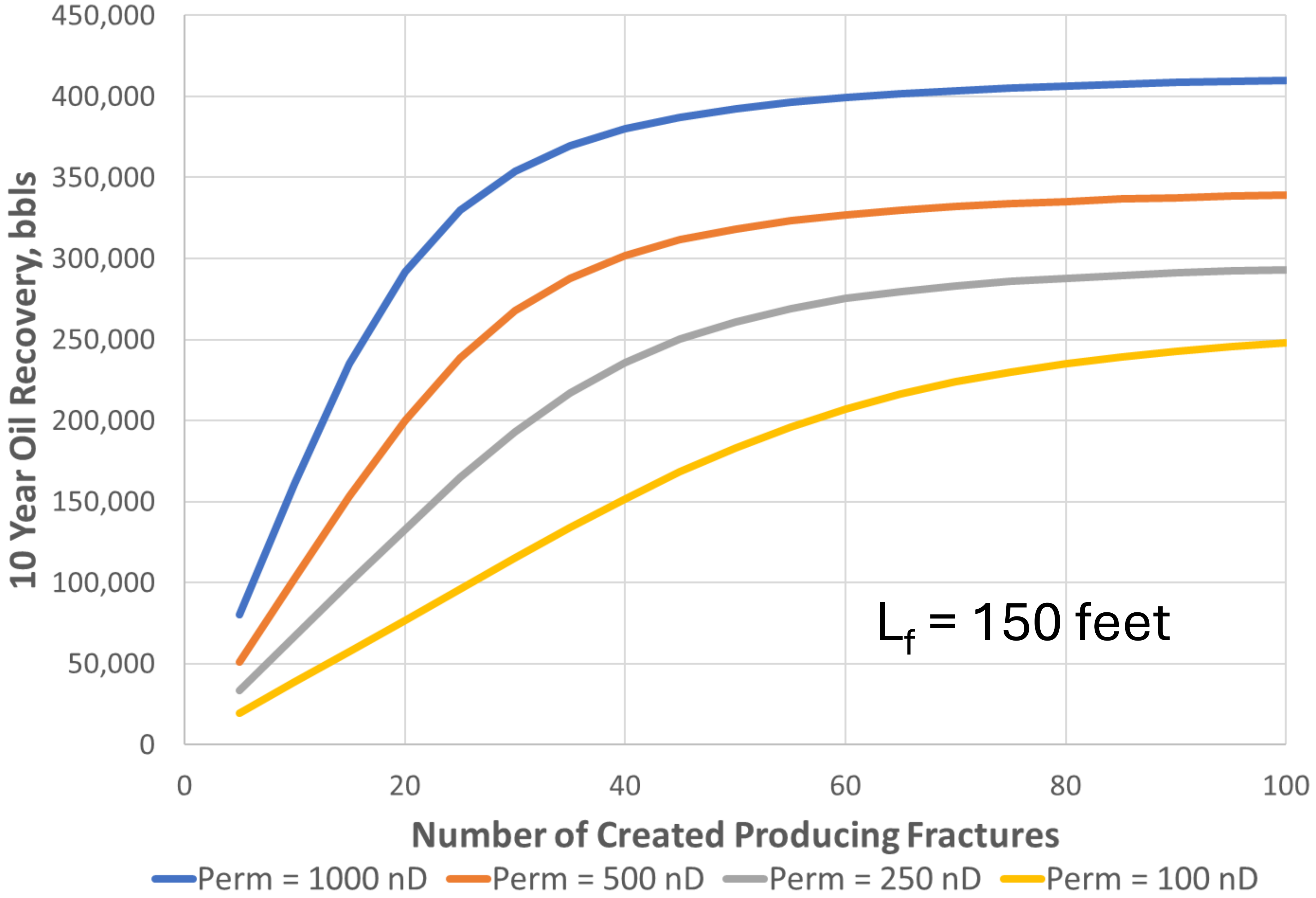


Figure 10 - Ten Year Cumulative Oil Recovery v. Created Fractures

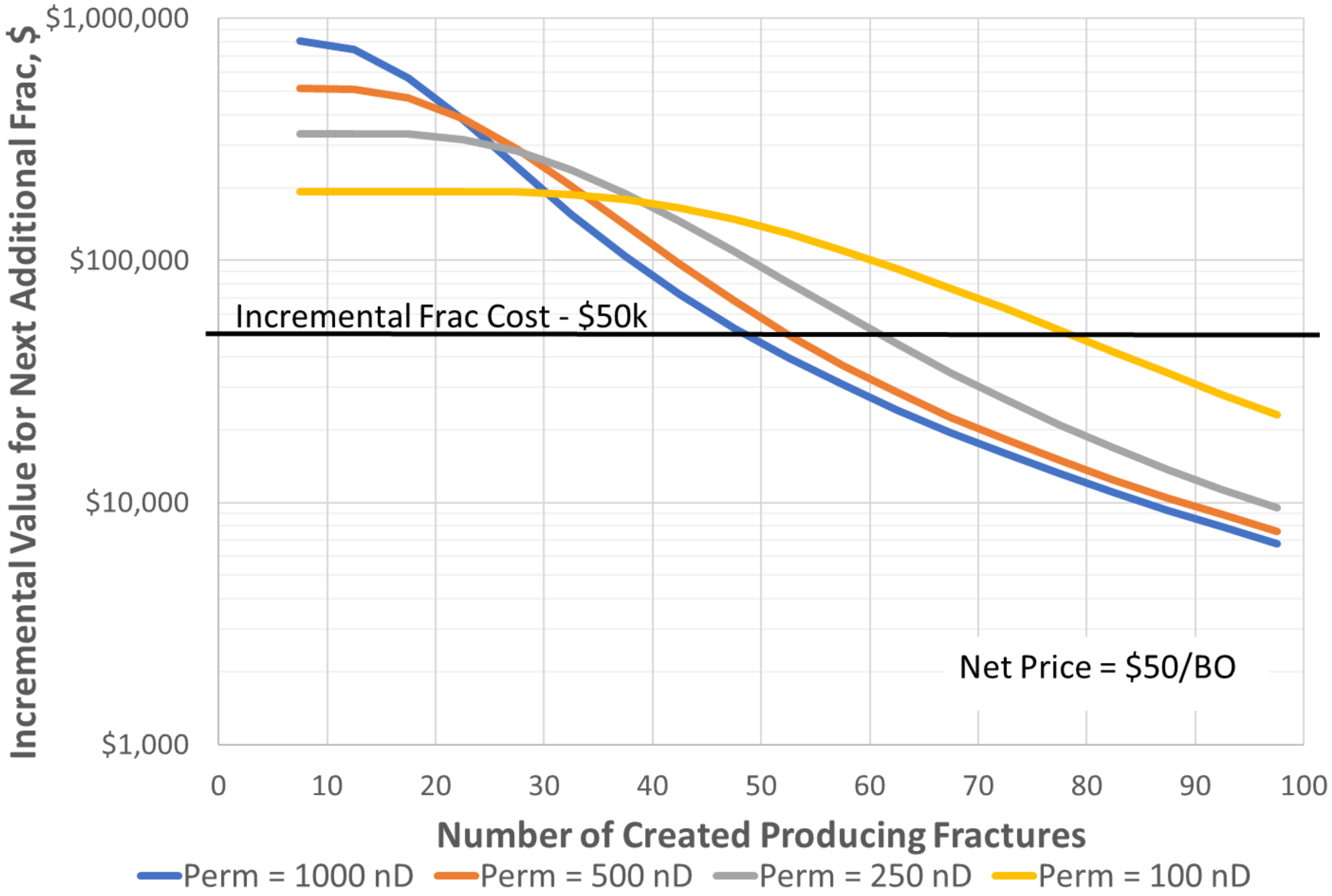


Figure 11 - Incremental Values Added by Next Fracture - Parametric Study

Case History

- Six producing wells in Powder River Basin
  - Mowry formation
  - Operated by EOG
  - All data from Public Sources
- Production History Match all wells
- Build trends for L_f vs. Treatment Size
- Estimate costs
- Evaluate Opportunity for Completion Design Optimization

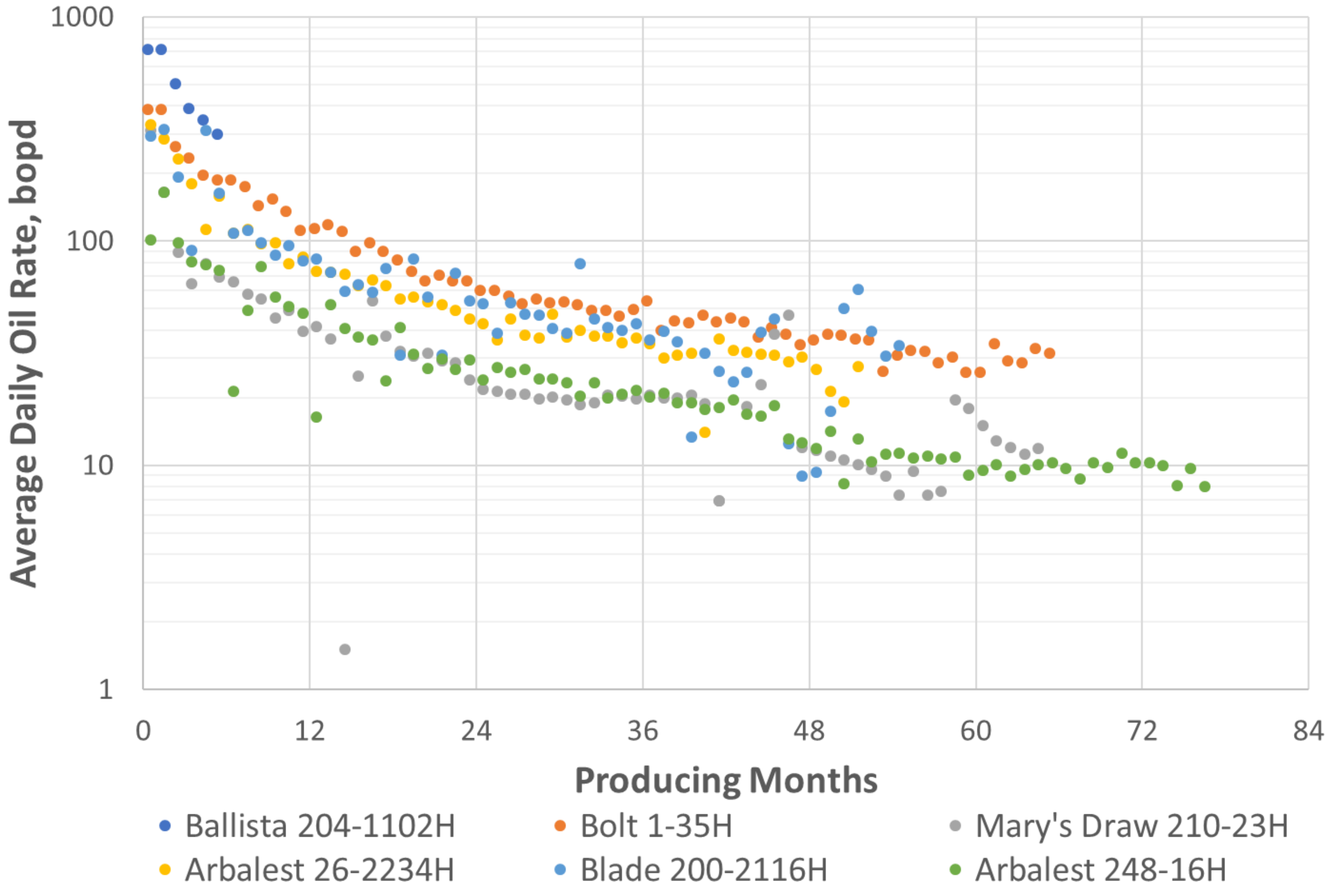


Figure 14 - Producing history from 6 Powder River Basin Mowry wells

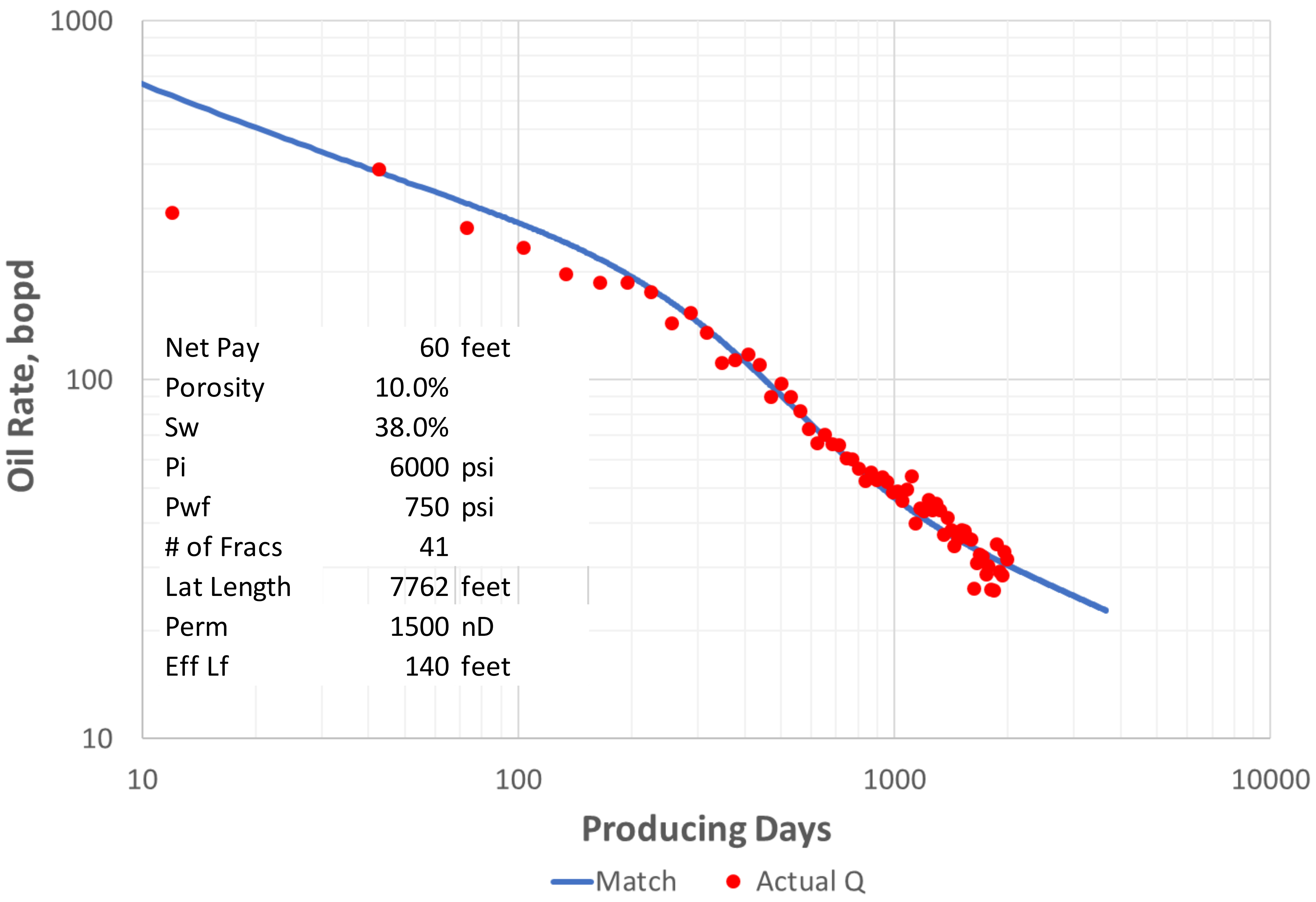


Figure 15 - Production History Match Bolt 1-35H

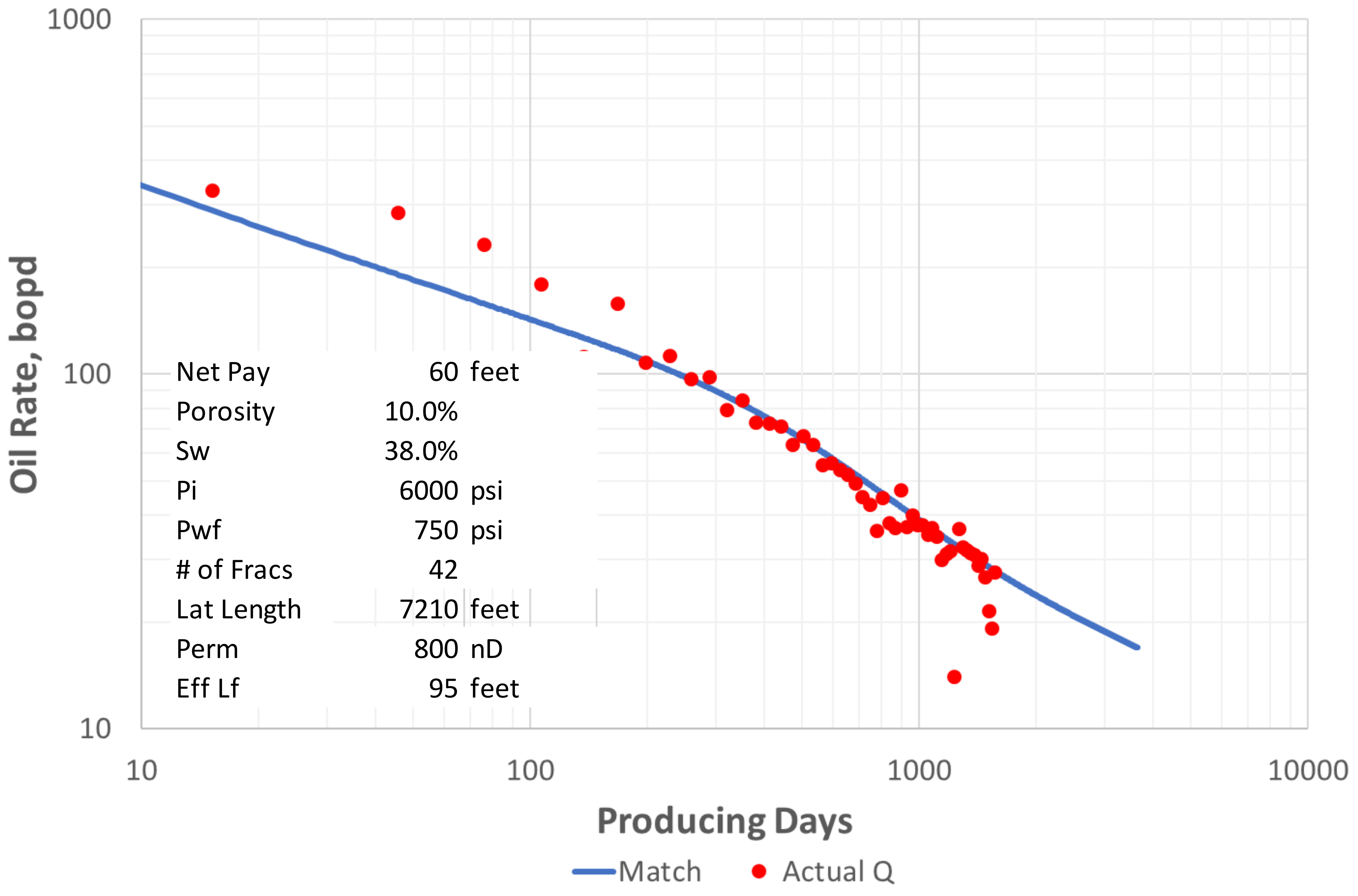


Figure 16 - Production History Match Arbalest 26-2234H

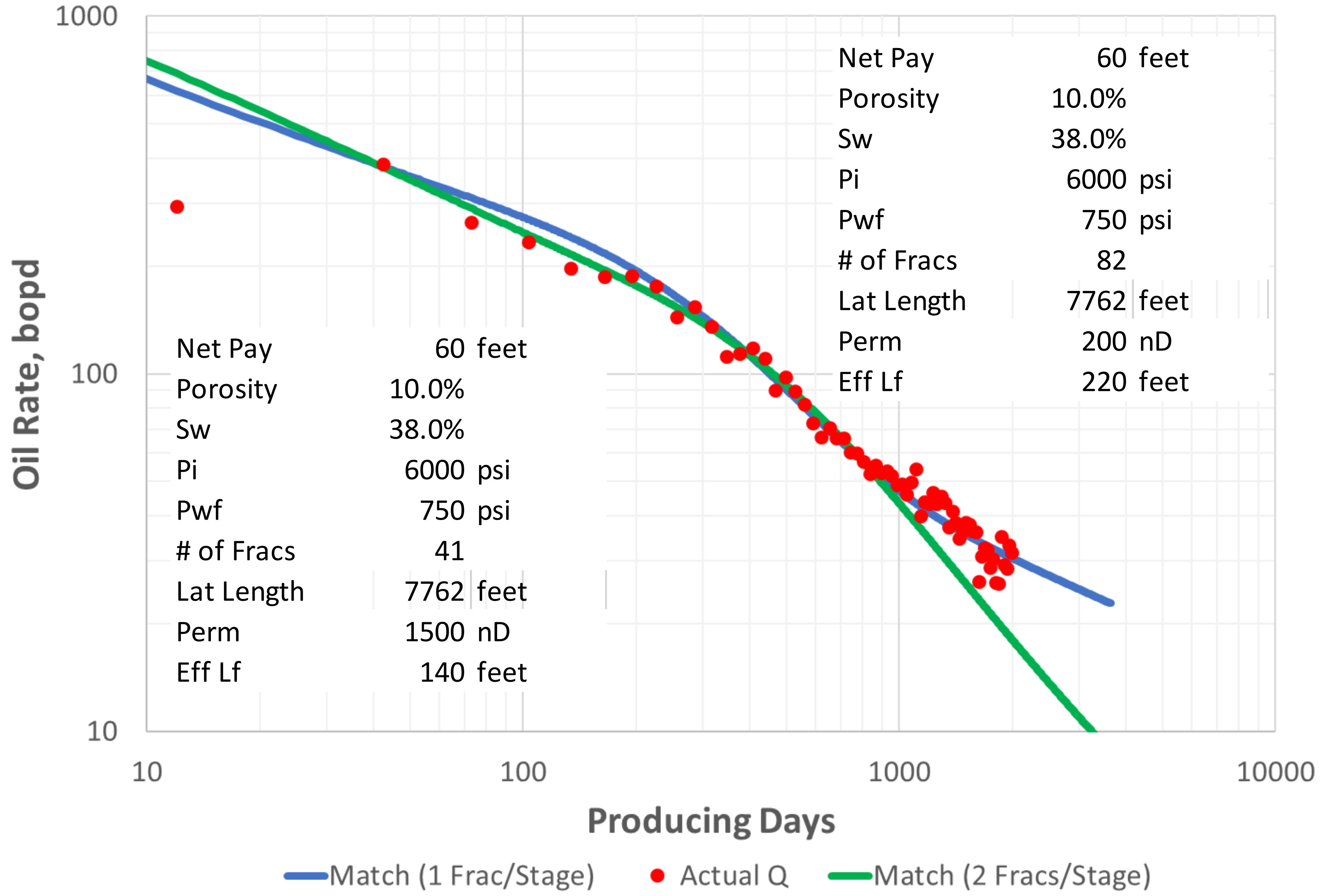


Figure 17 - Production History Match Bolt 1-35H - Compare using 2 Fracs/Stage

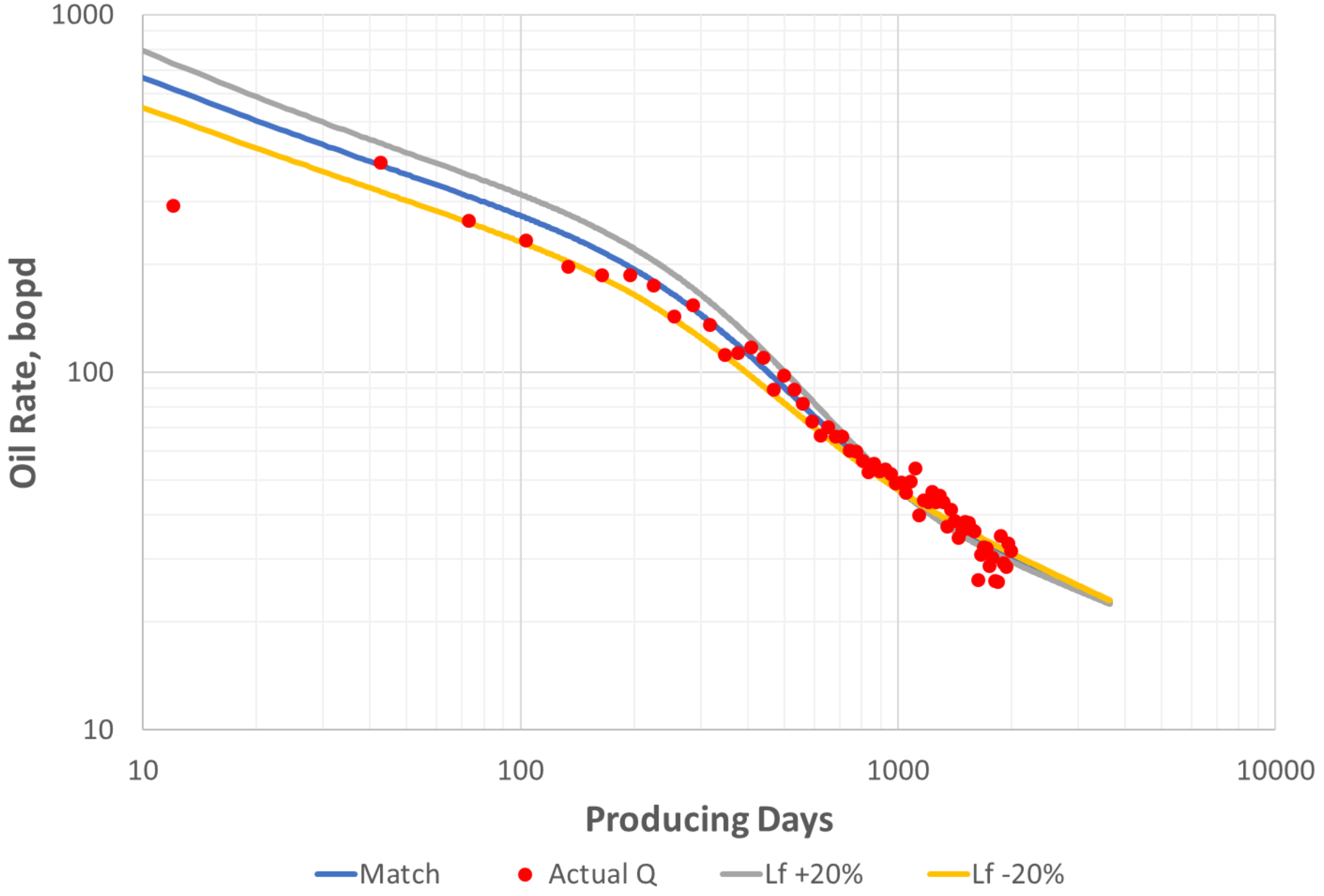


Figure 18 - Production History Match Bolt 1-35H - Sensitivity to Effective Fracture Half-Length

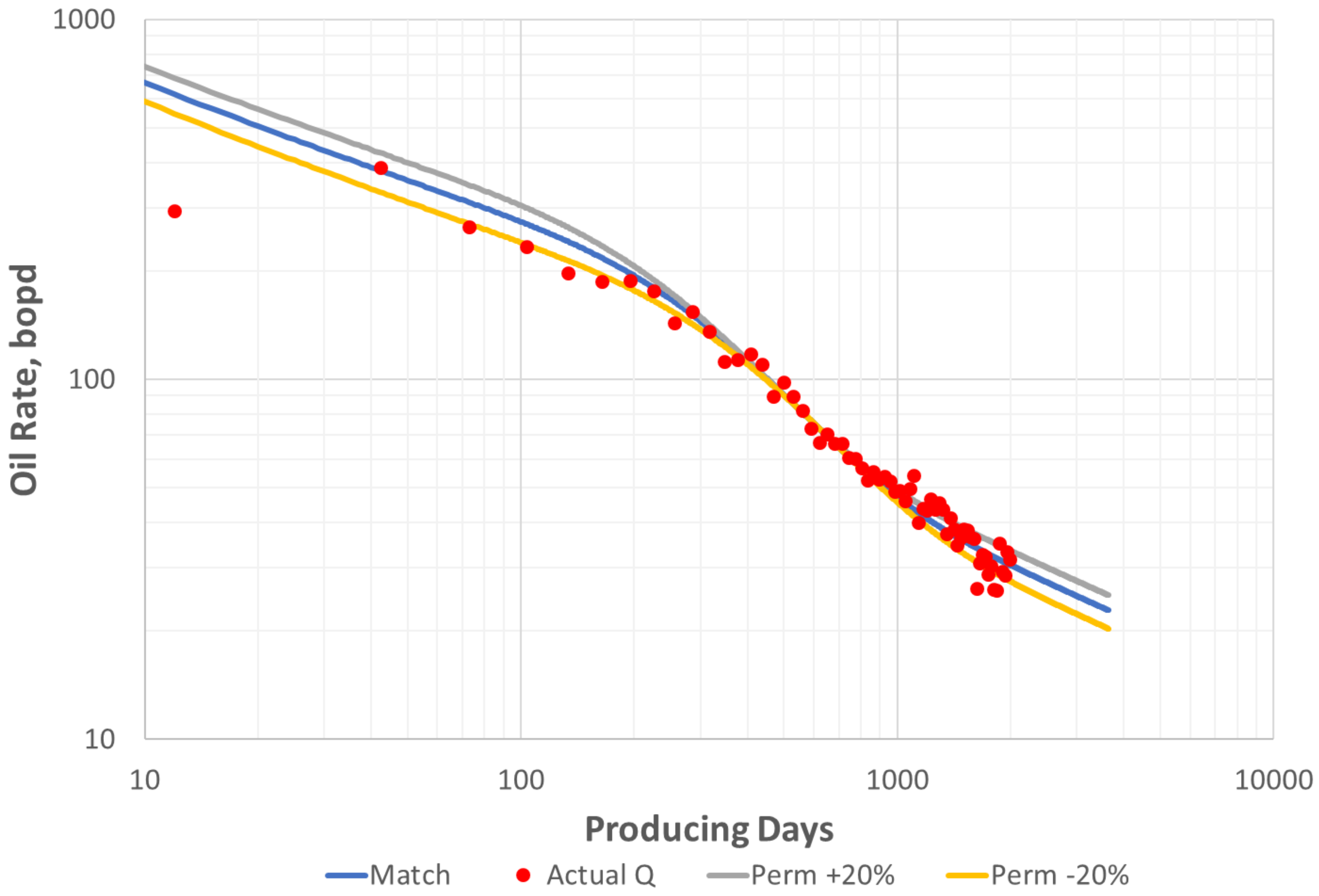


Figure 19 - Production History Match Bolt 1-35H - Sensitivity to Permeability

Production History Match Results

Table 3

Lease Name	Well Number	Date Production Start	Lateral Length feet	Stages	Fluid Pumped per Stage gallons	Sand Pumped per Stage lbs	Matched Effective Lf feet	Matched Permeability nD
ARBALEST	248-16H	7/1/2012	3400	23	78,666	36,750	70	1600
BOLT	1-35H	6/1/2013	7767	41	199,702	355,079	140	1500
MARYS DRAW	210-23H	7/1/2013	3527	23	159,684	308,947	110	700
BLADE	200-2116H	10/1/2013	6283	36	188,945	313,224	95	1400
ARBALEST	26-2234H	8/1/2014	7210	42	153,357	236,106	95	800
BALLISTA	204-1102H	6/1/2018	8962	55	345,769	478,482	205	1700

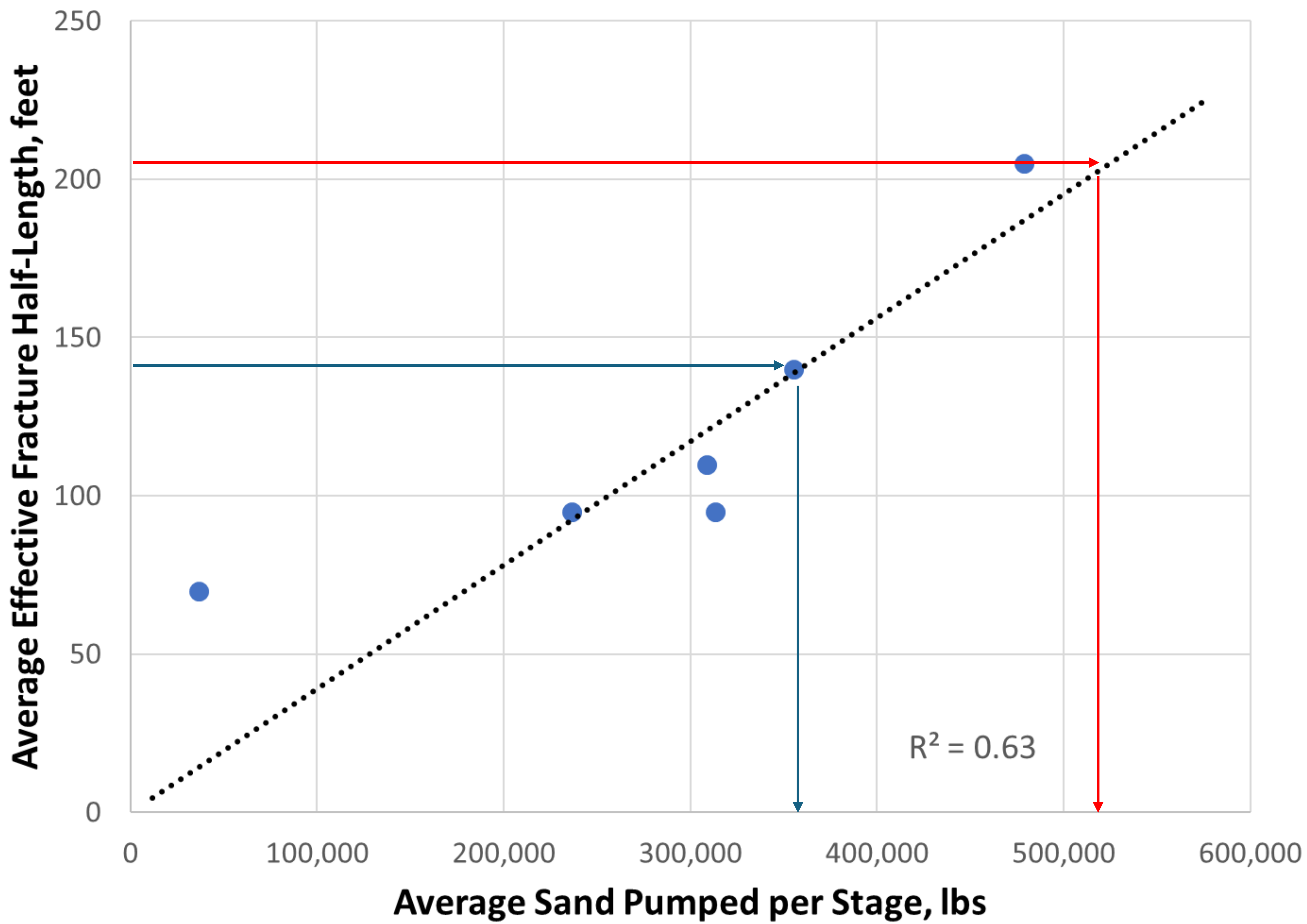


Figure 20 - Average Sand Pumped versus Matched Effective Fracture Half-Length

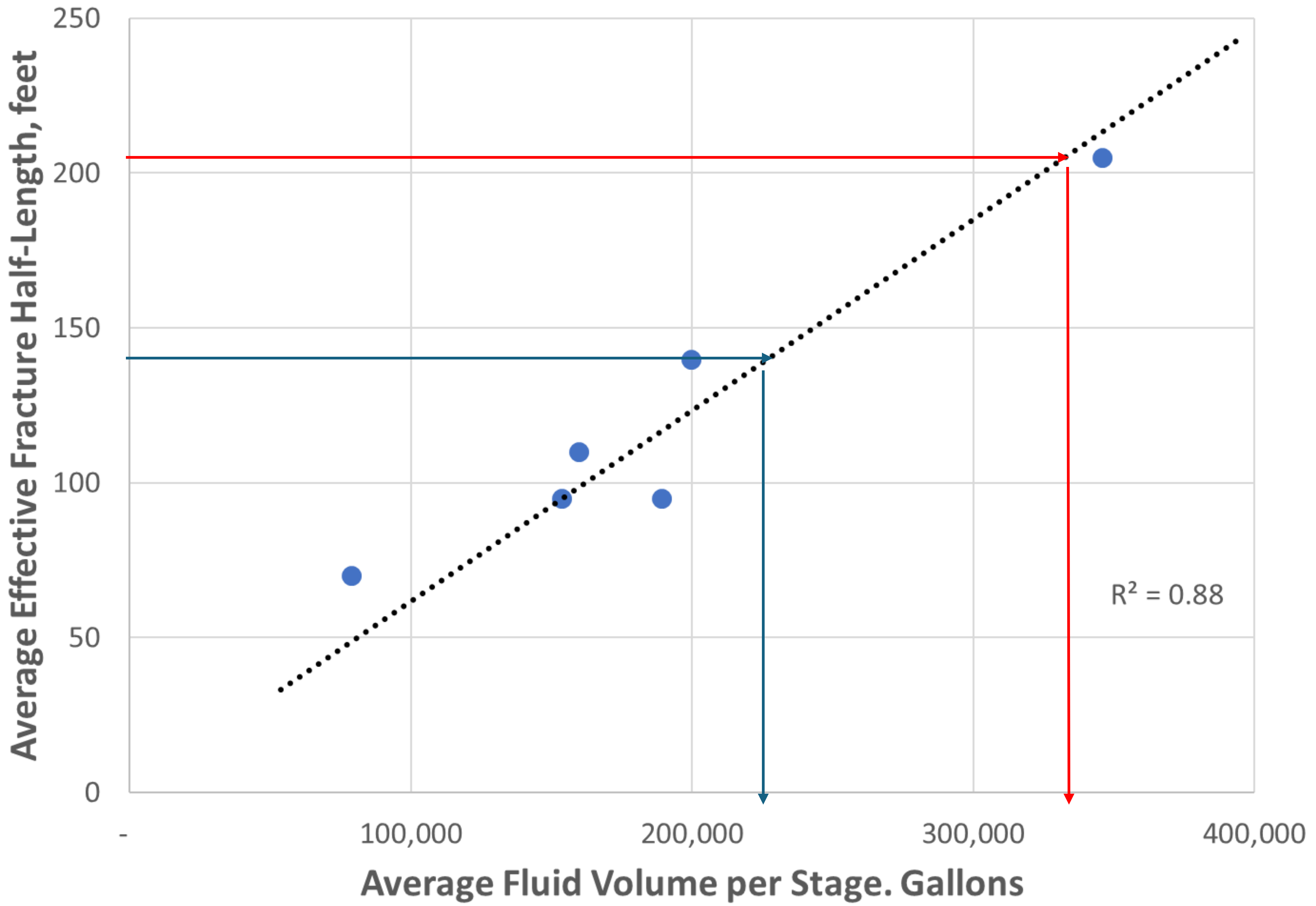
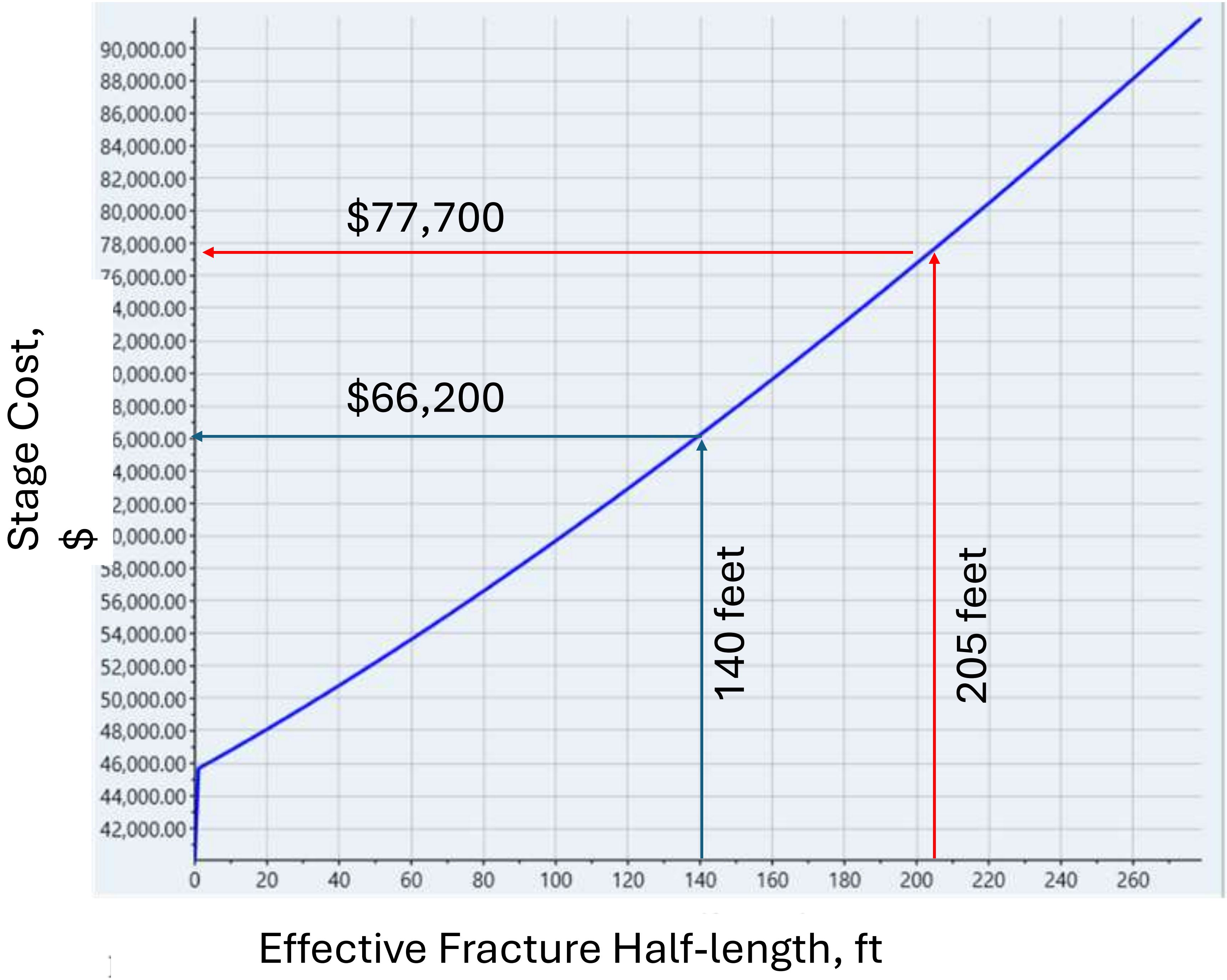


Figure 21 - Average Fluid Pumped versus Matched Effective Fracture Half-Length



Stage Cost, $
Effective Fracture Half-length, ft
$77,700
$66,200
140 feet
205 feet
90,000.00
88,000.00
86,000.00
84,000.00
82,000.00
80,000.00
78,000.00
56,000.00
54,000.00
52,000.00
50,000.00
48,000.00
46,000.00
44,000.00
42,000.00
0
20
40
60
80
100
120
140
160
180
200
220
240
260

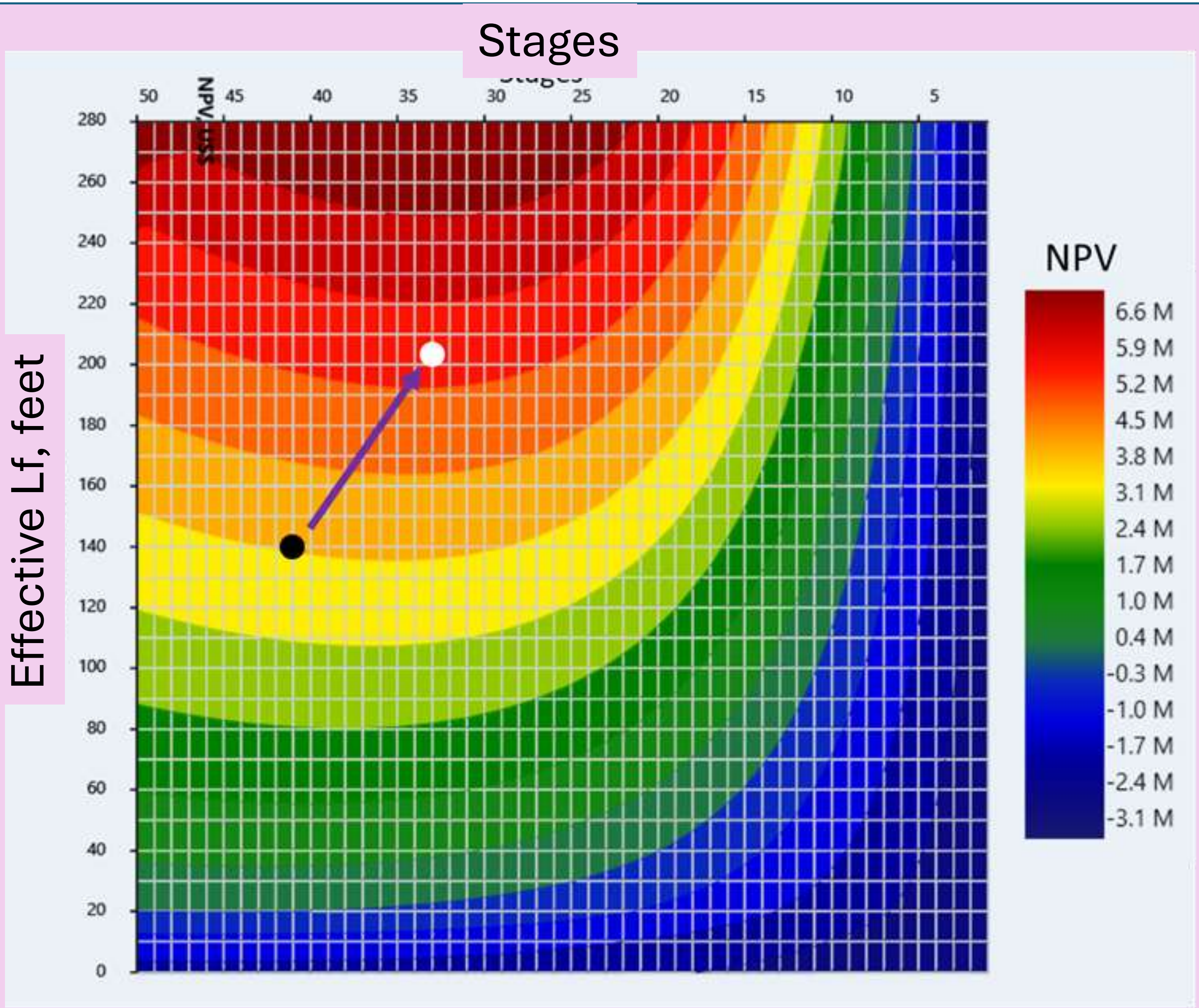
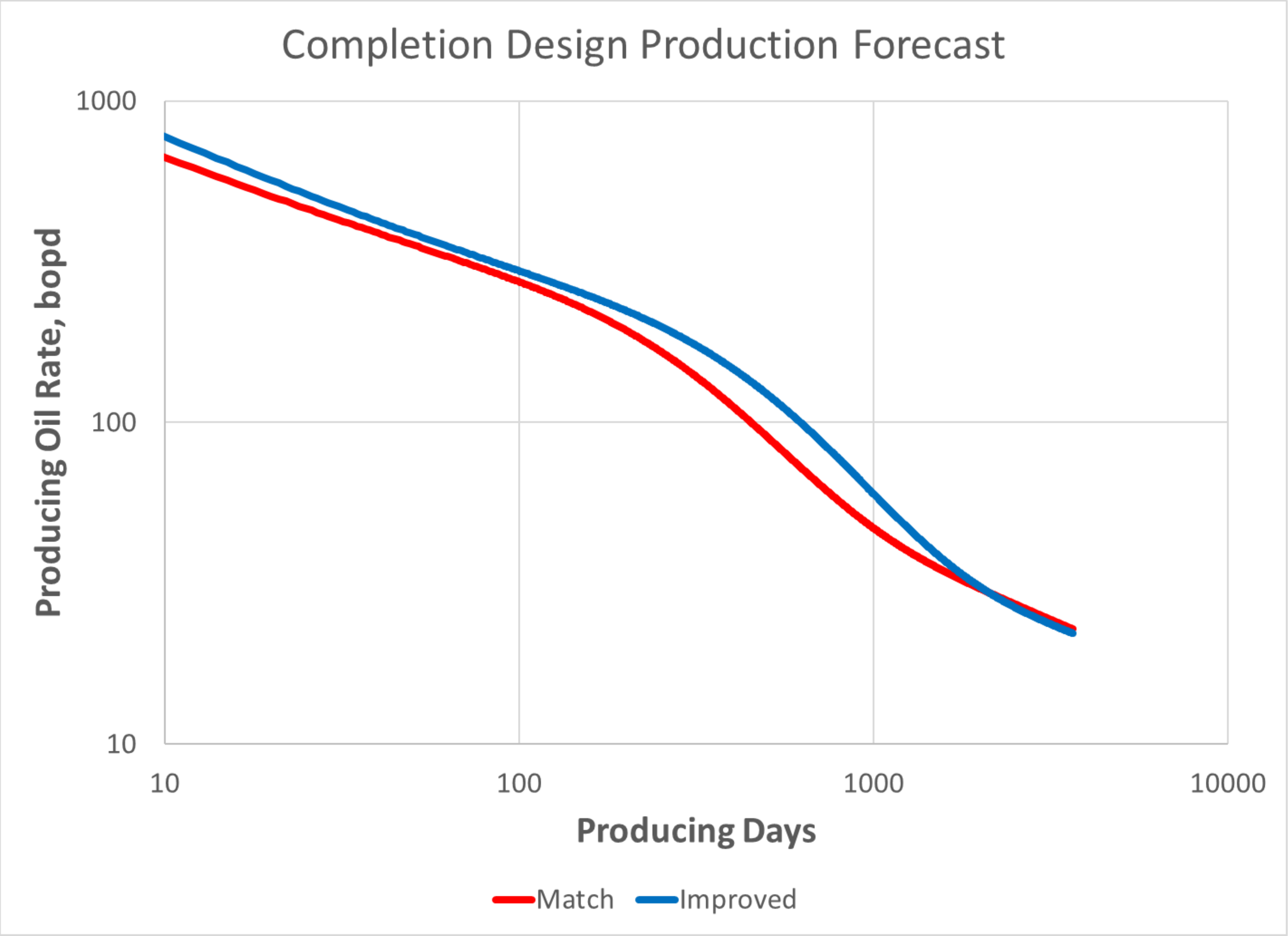


Figure 23 – NPV Outcome for a Matrix of Completion Designs


Completion Design Production Forecast
1000
100
10
Producing Oil Rate, bopd
10
100
1000
10000
Producing Days
Match
Improved

Actual Completion Design

# Of Stages	41
Entry Points	1
Effective Lf (ft)	140
Proppant Type	40/70 White Sand
Max Prop Conc. (ppg)	2.2
Stage Cost	$66,218.73
Total Well Cost	$5,464,967.74
NPV	$3,160,310.05
ROI	1.58
Hydrocarbons Produced	223,222

Improved Completion Design

# Of Stages	33
Entry Points	1
Effective Lf (ft)	205
Proppant Type	40/70 White Sand
Max Prop Conc. (ppg)	2.1
Stage Cost	$77,683.36
Total Well Cost	$5,313,550.83
NPV	$4,802,820.99
ROI	1.90
Hydrocarbons Produced	256,688

Reduce Well Cost by $141,000 (-2.5%)
Increase NPV by $1.64 million (+52%)
Increases Drainage Area
Reduces number of wells required to drain acreage

Conclusions

- Significant cost savings and increased per well profit can be realized by analyzing fracture treatment data and production data to characterize both the hydraulic fractures created and the reservoir properties as input into an economic model.

- The production decline behavior of unconventional wells can be analyzed using an analytical solution to characterize average permeability, average effective fracture half-length and number of effective fractures created.

Conclusions

- Knowledge of effective fracture half-length and formation permeability can aid in the spacing of wells in field development.

- Knowledge of treatment size versus effective fracture half-length can lead to increased hydrocarbon recovery and improved well economics by designing the optimum fracture treatments for specific formation properties

Conclusions

- Our analyses over the past few years leads us to the conclusion that many operators are using too many fracture treatment stages and too many clusters per stage to maximize initial production (IPs) rates at the expense of net present value and return on investment.

- In many reservoirs, increasing well spacing, reducing the number of stages, and creating longer hydraulic fractures will result in a better return on investment.

Summary

- Results
- Location
- Principles
- Analysis
- Recommendations
- Results (again)
- Conclusions

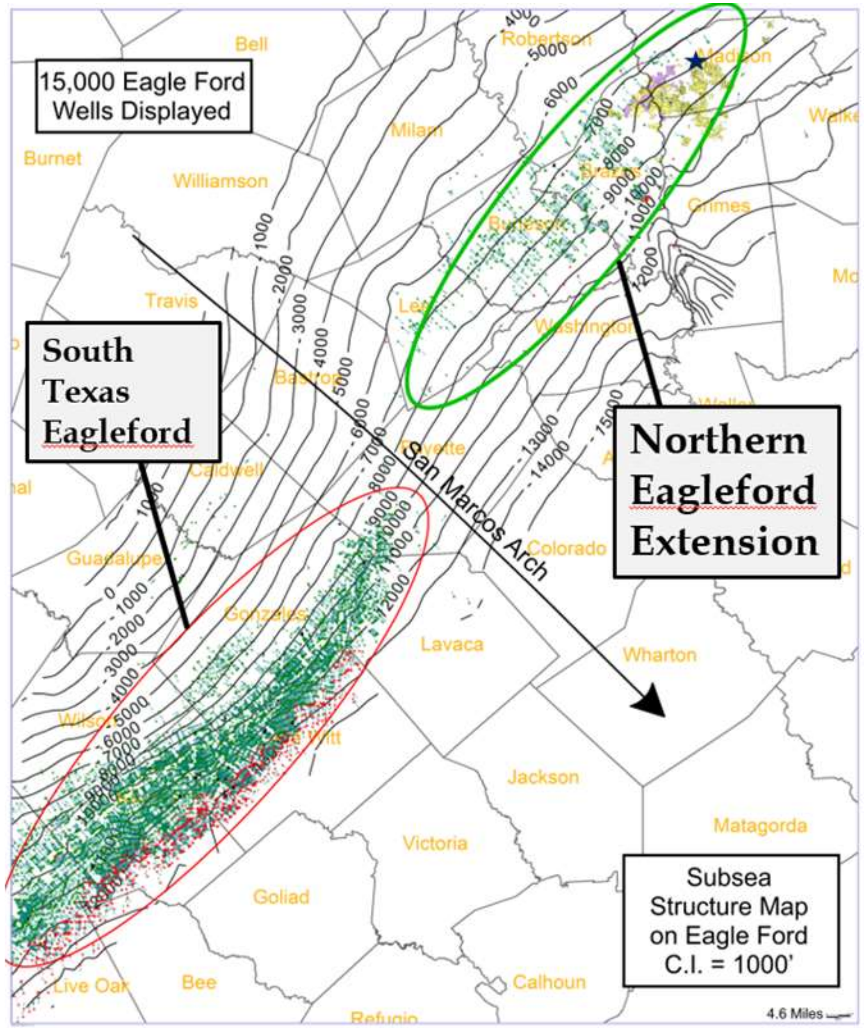
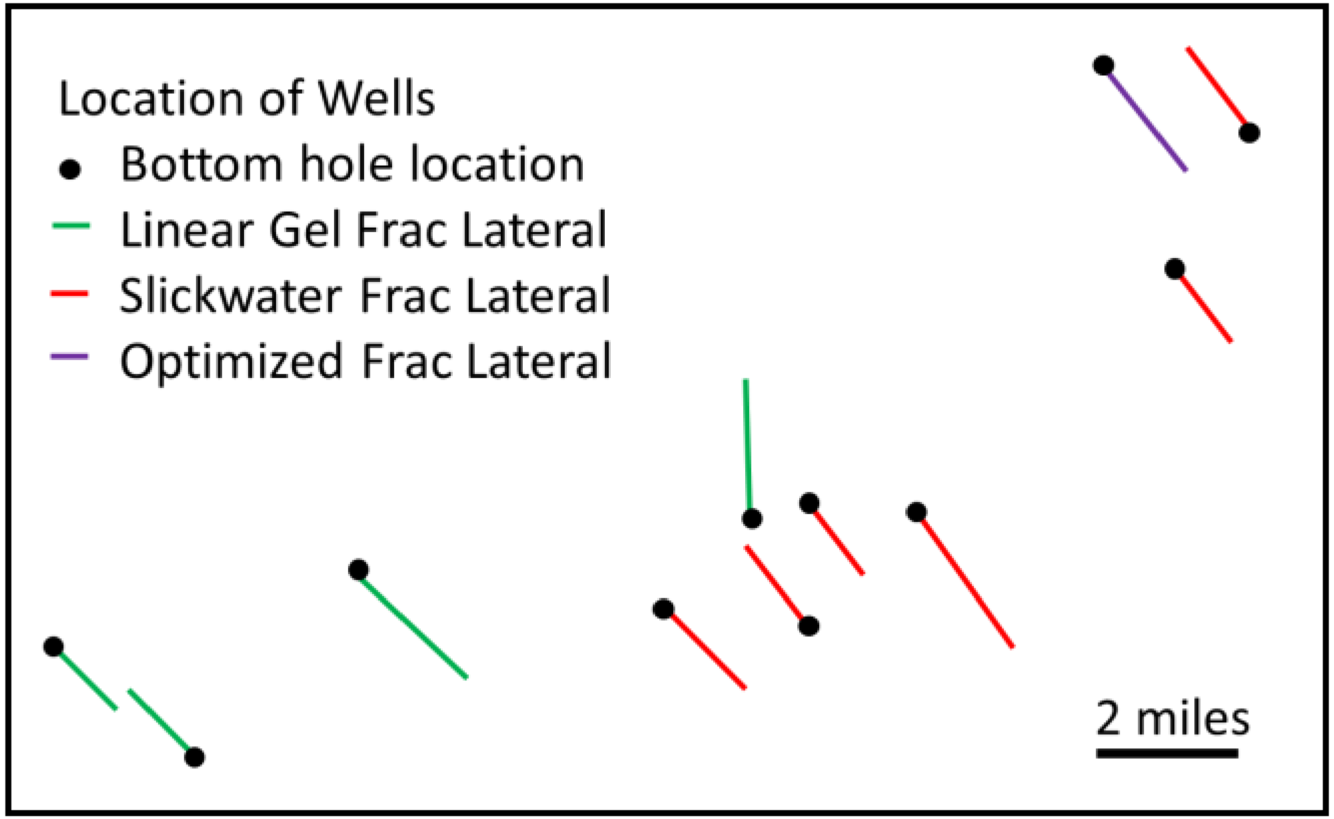


Figure 1 – Map of Evaluation Area

- Located in the Northern Eagleford Extension
- Near the town of North Zulch



All horizontal, multi-stage completions with transverse hydraulic fractures decline in a similar manner

Early-time Linear Flow – Pressure transient is moving outward from the created fracture faces

Transitional Flow – Pressure transient between fractures have met and depletion of the SRV occurs

Late-time Linear Flow – Flow from the reservoir moves linearly into the depleted SRV

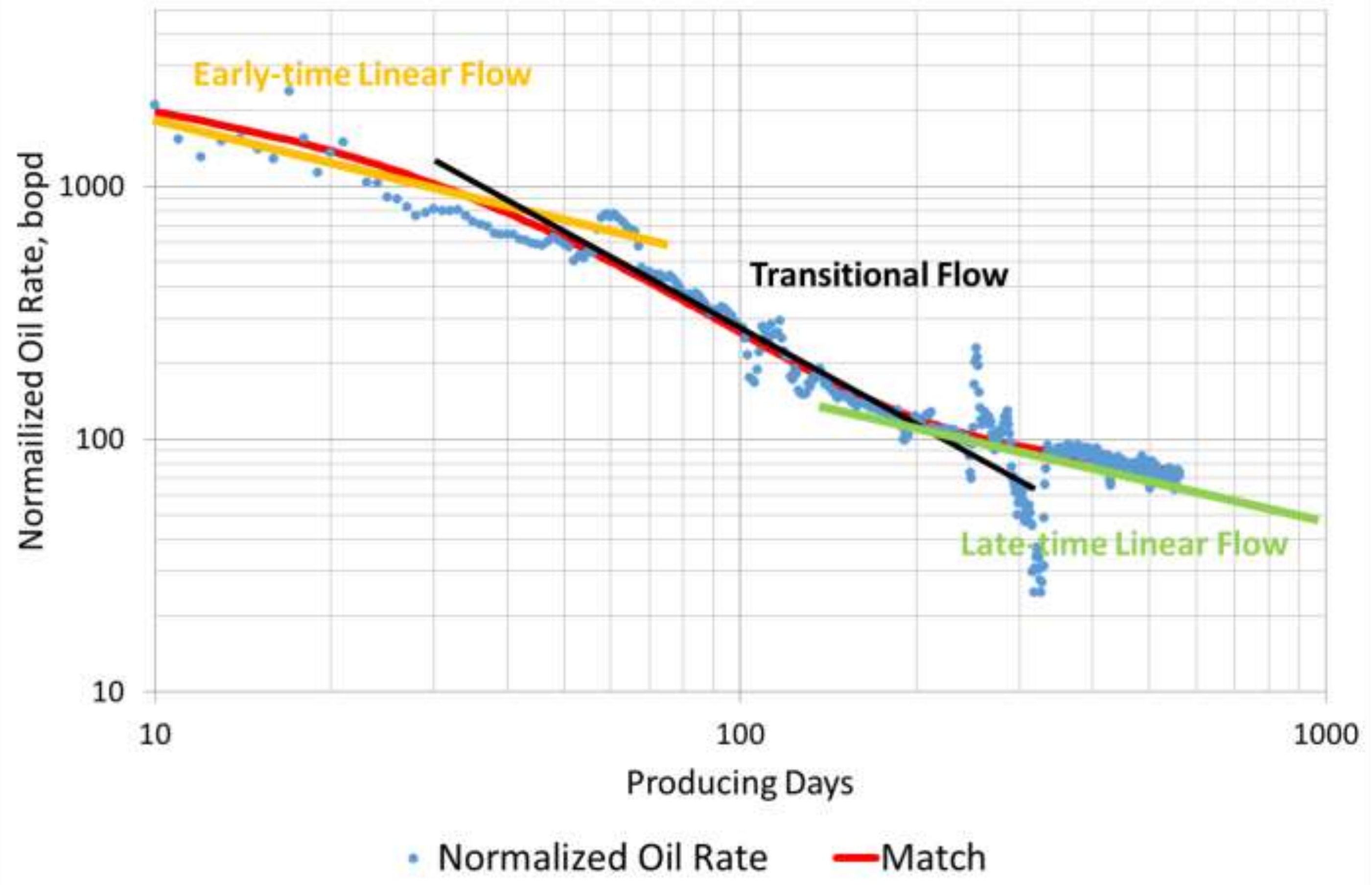
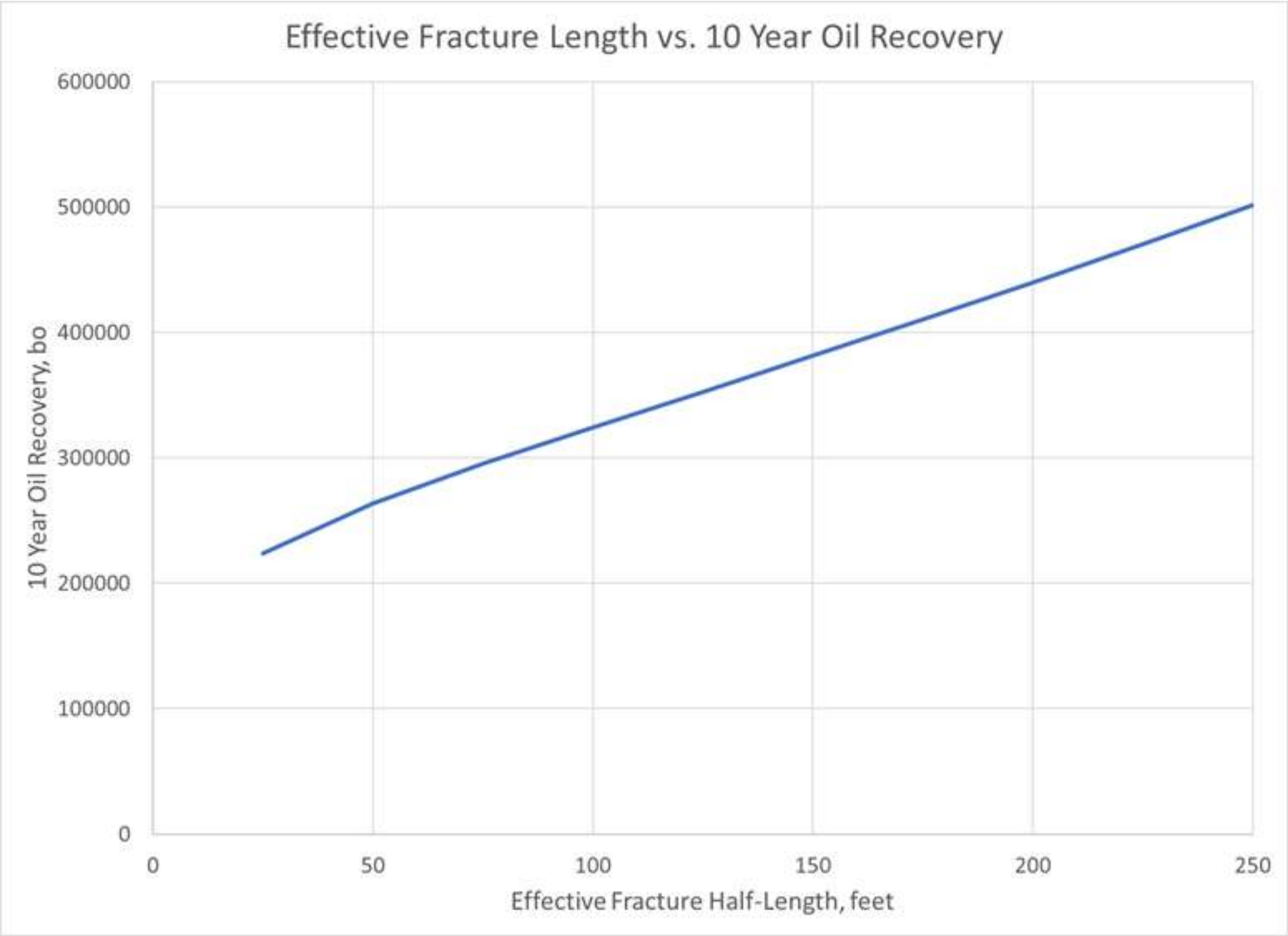


Figure 2 - Producing History Example - West Texas (Bone Springs)

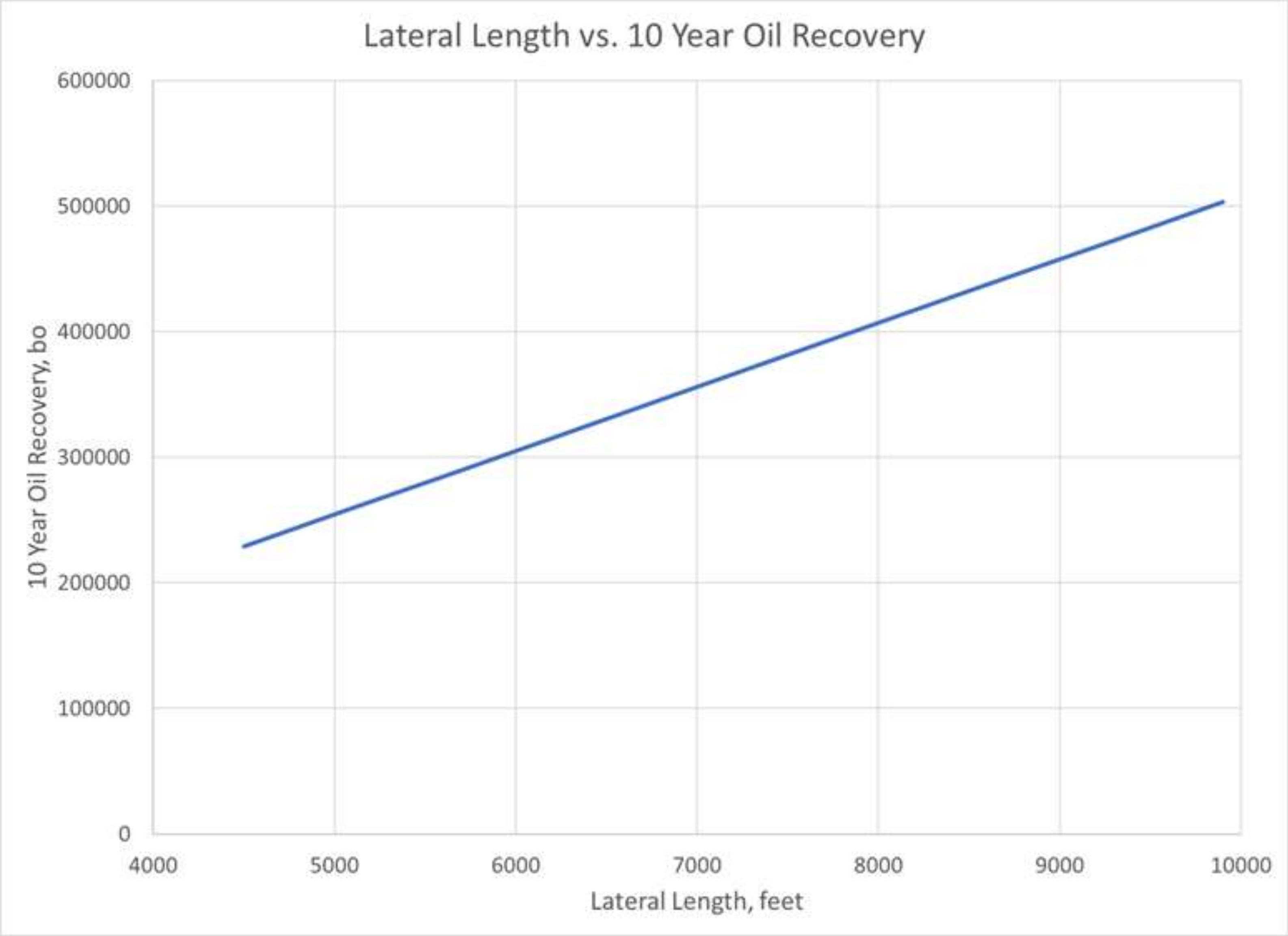
All other properties being equal, increasing effective fracture half-length increases the 10-year recovery

This is because the SRV is increased and recovery is proportional to the size of the SRV.



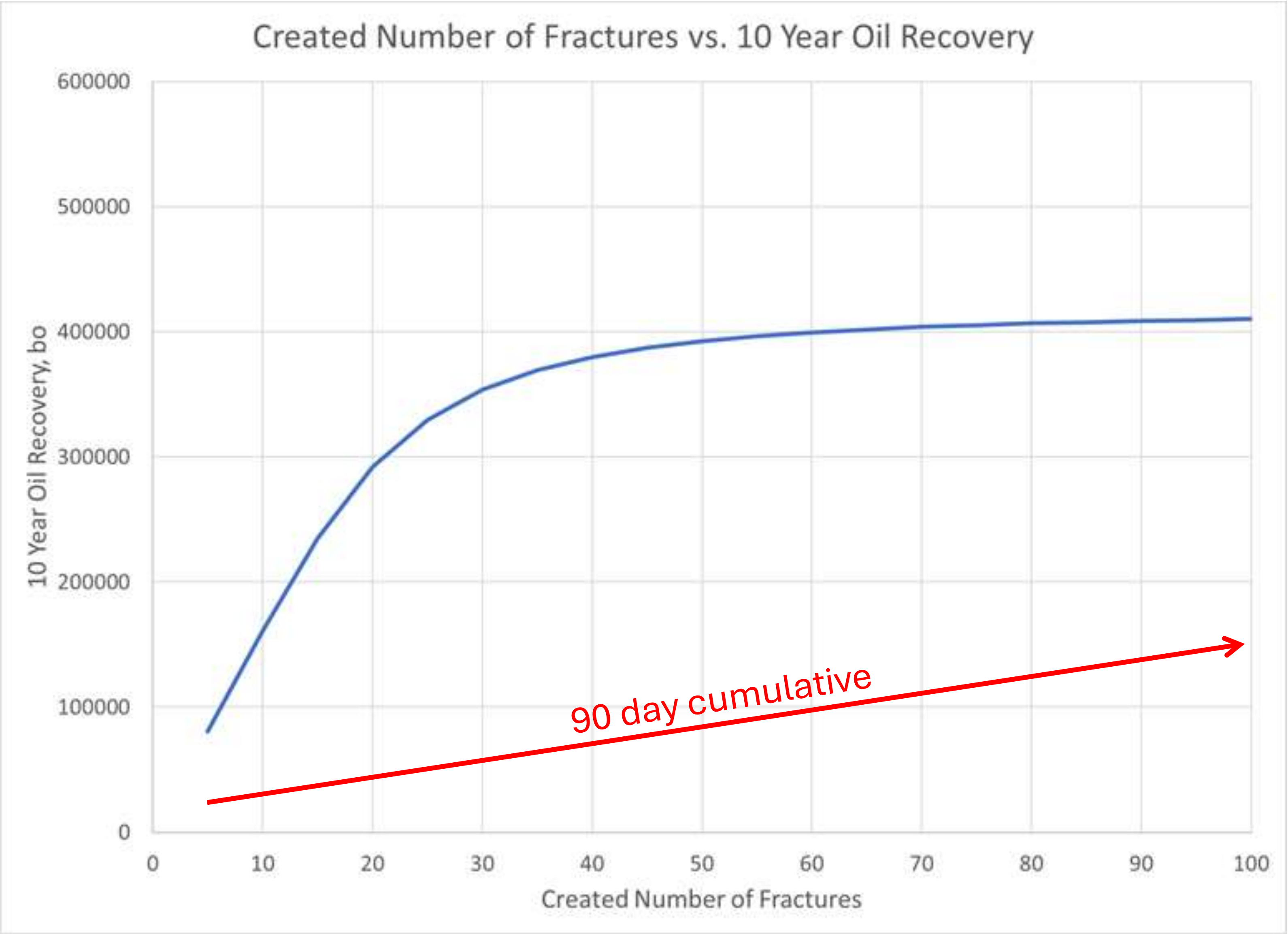
All other properties being equal, increasing the lateral Length increases the 10-year recovery

This is because the SRV is increased and recovery is proportional to the size of the SRV.



All other properties being equal, increasing number of effective fractures along the lateral has a diminishing return on 10-year recovery

This is because the SRV is not increased. The increased density of the fractures is only recovering oil within the SRV



- Example of production history match
- Non-Unique match overall
- Unique matches possible upon assuming # of fractures created per stage
- Unique matches attained on wells with Late-time linear flow
- Estimating maximum number of fractures created at 2 based on many observations

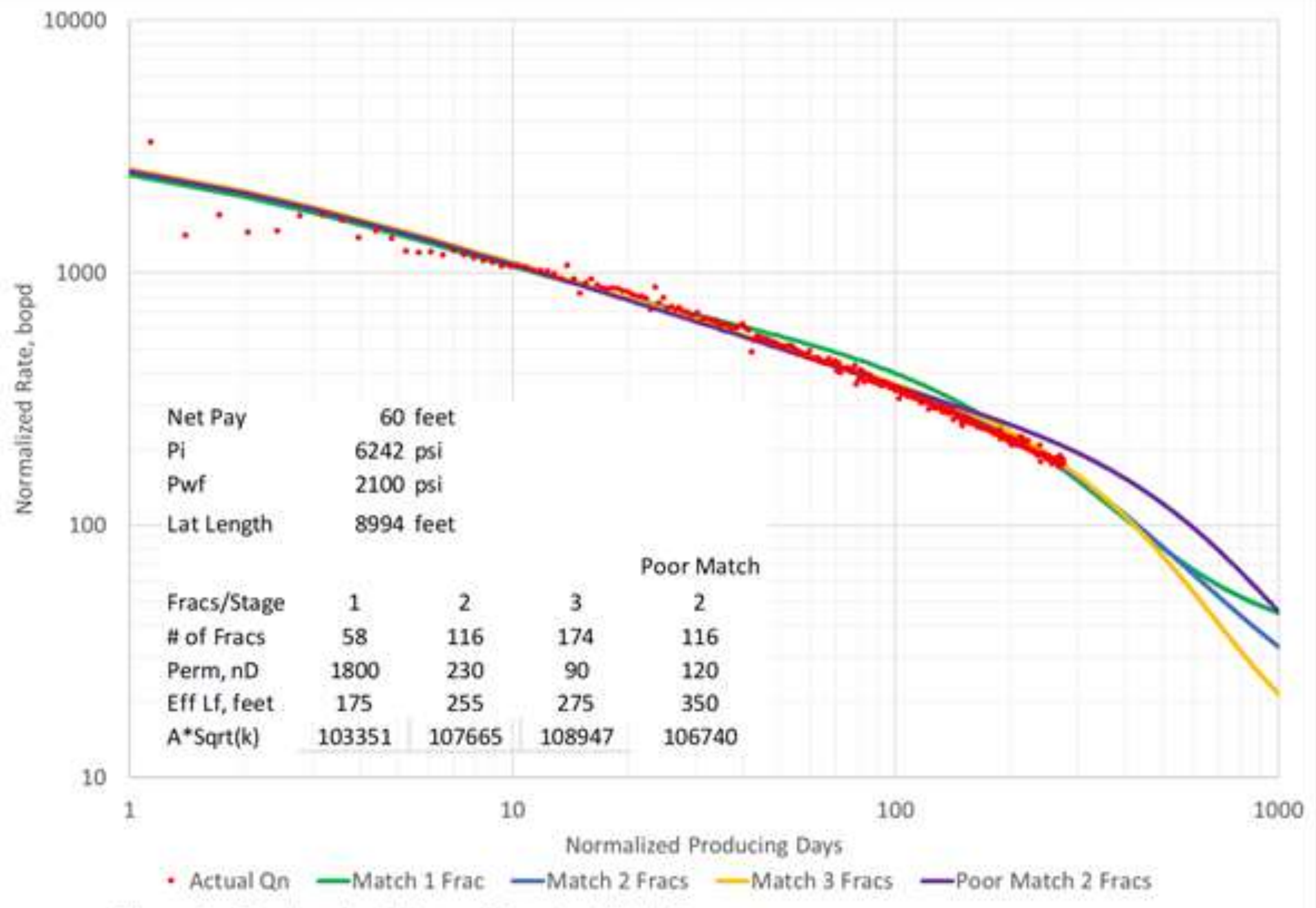


Figure 3 - Production History Match of Well 2

- Understanding treatment volumes versus effective fracture half-length
- From treatment size we can determine treatment cost versus effective fracture half-length achieved
- Knowing this we can determine the well costs for all possible completion designs

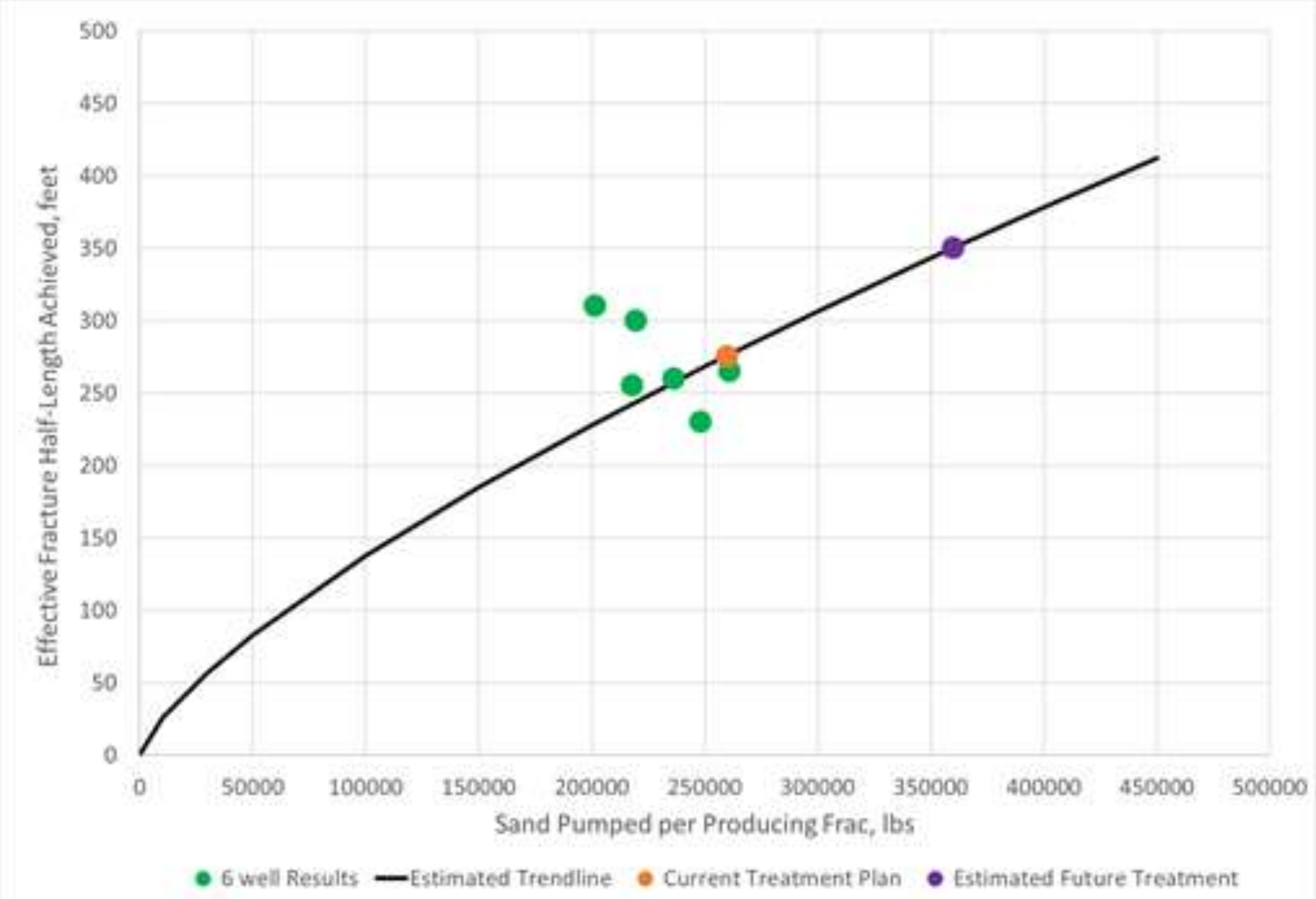


Figure 4 - Treatment Size Vs. Effective Lf Achieved

Distribution of permeability from previous wells

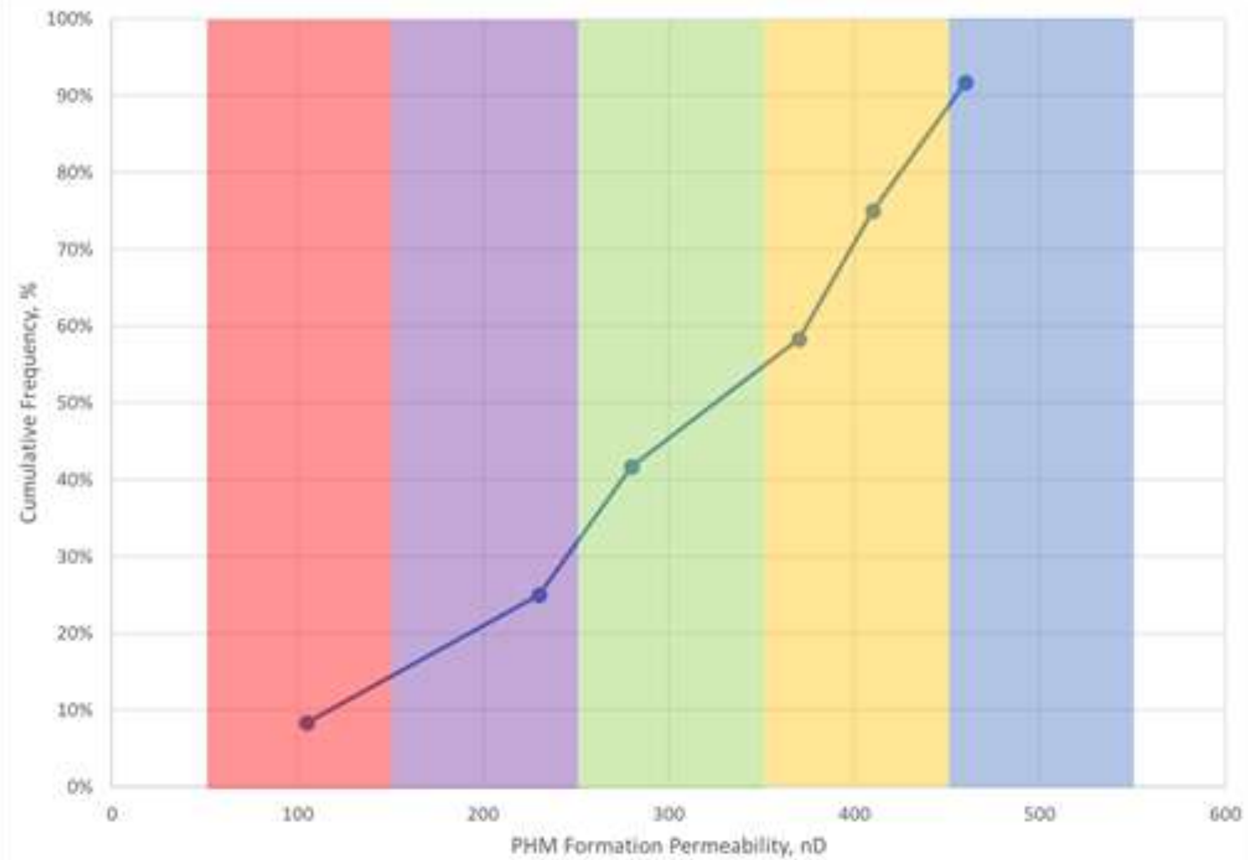


Figure 7 - Cumulative Distribution of Formation Permeaability from Production History Matching

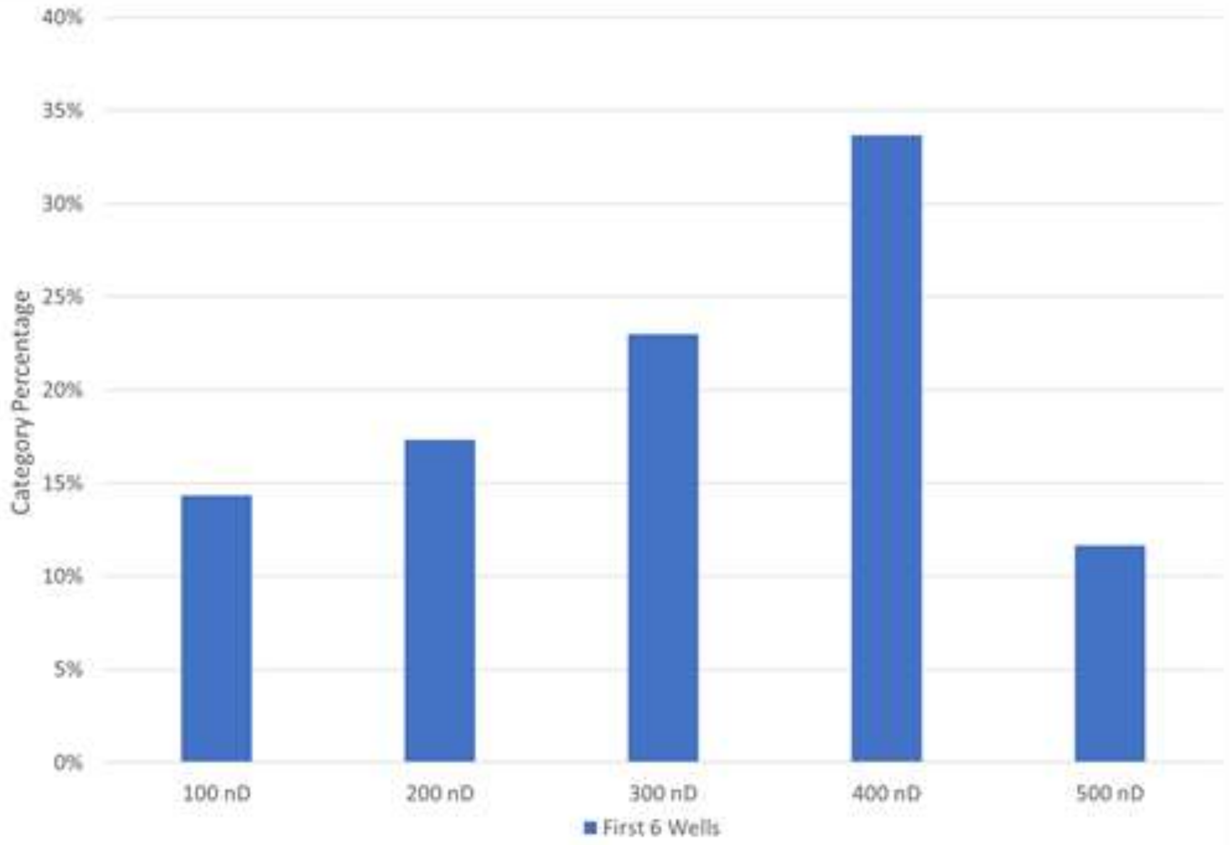


Figure 8 - Distribution of Formation Permeability

- We can determine the optimum number of stages for each permeability category
- This ranges from 34 stages up to 52
- Current practice calls for 57stages for a 10,000 ft lateral

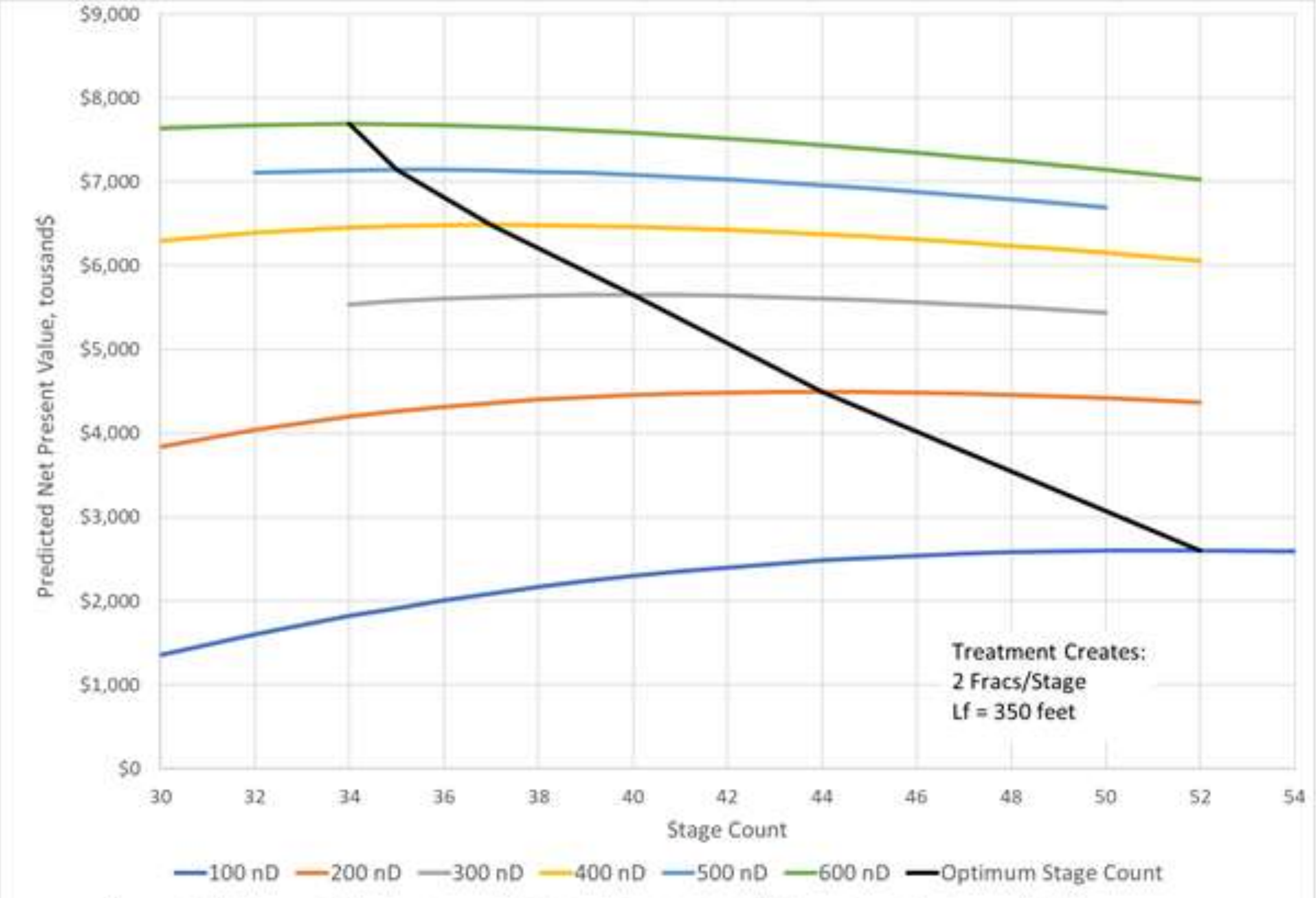


Figure 6 - Net Present Value Outcome for Designed Treatment for Various Formation Permeabilities

- Using the NPV curves from the previous slide we can determine the number of stages that maximizes the NPV given the permeability distribution of the existing wells
- We find that 40 – 42 stages result in the highest NPV

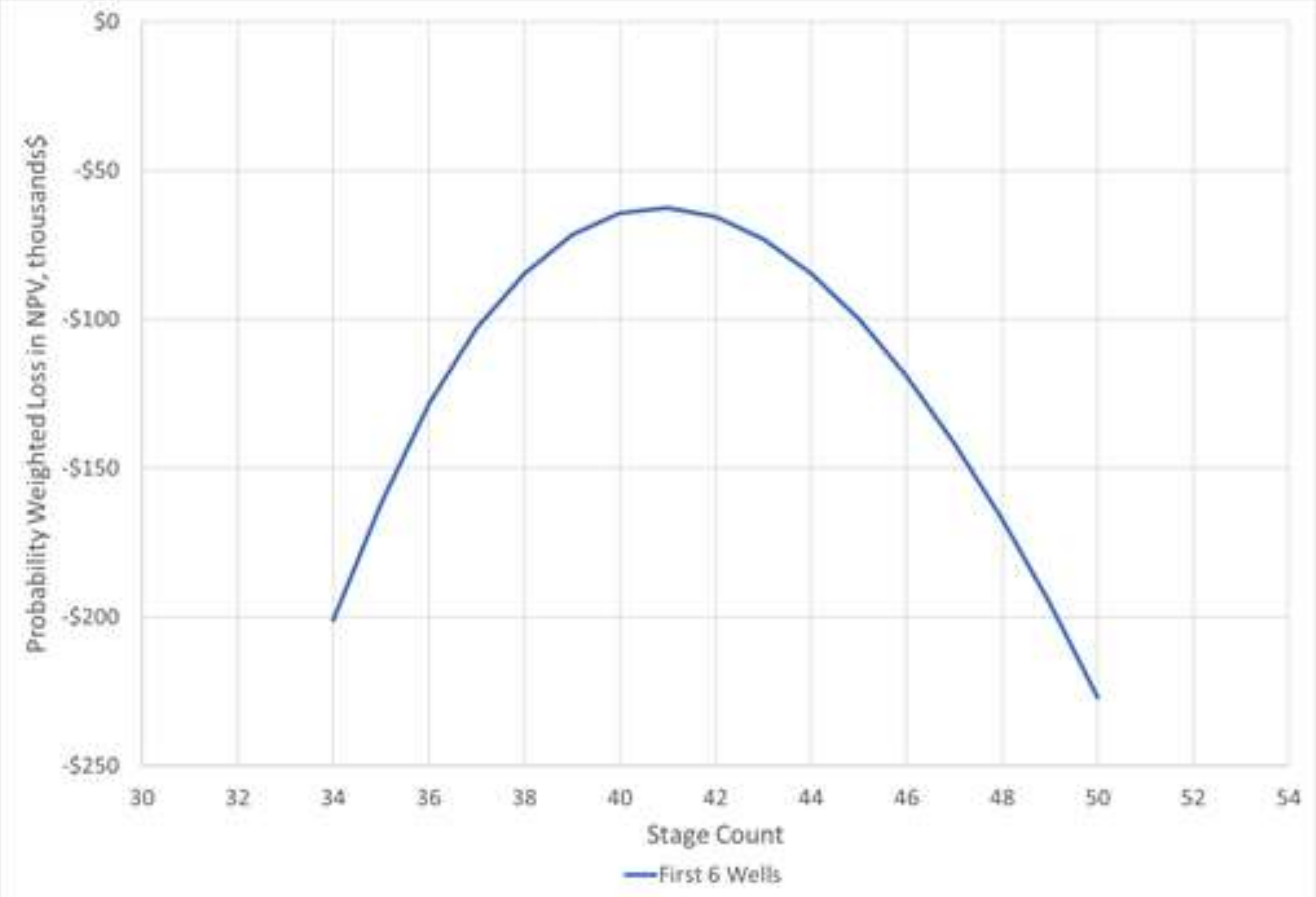


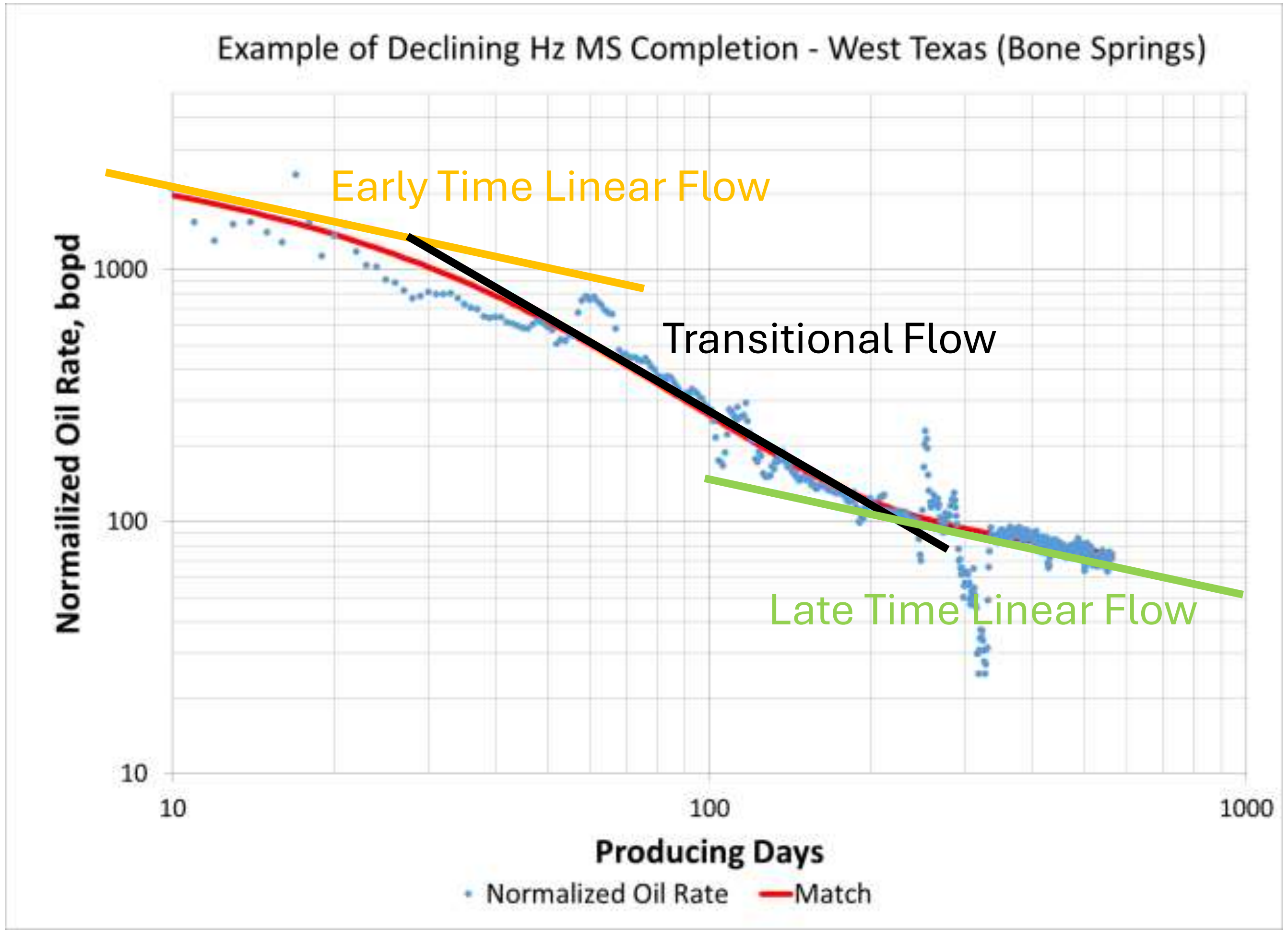
Figure 9 - Probability Weighted Loss in NPV from Stage Count Selection

Conclusions

- Production history matching can be used to determine reservoir quality and completion properties
- Forward modeling can be used to forecast the effects of completion design changes and determine optimum designs for improved economics
- Using these methods can allow an operator to “LEAP” to optimum completion designs rather than “CRAWL” through the use of multiple well pilot cases
- The authors have seen similar opportunities and results in multiple basins and formations across the US

How does production decline in Hz wells?

- All Hz Multi-Stage well's production decline in a similar manner
  - Early Time Linear Flow
    - Dependent on the number and length of fracs created and the formation permeability
  - Transitional Flow
    - Depleting the SRV, beginning dependent on distance between fracs and formation permeability
  - Late Time Linear Flow
    - Magnitude and timing is dependent on formation permeability and lateral length



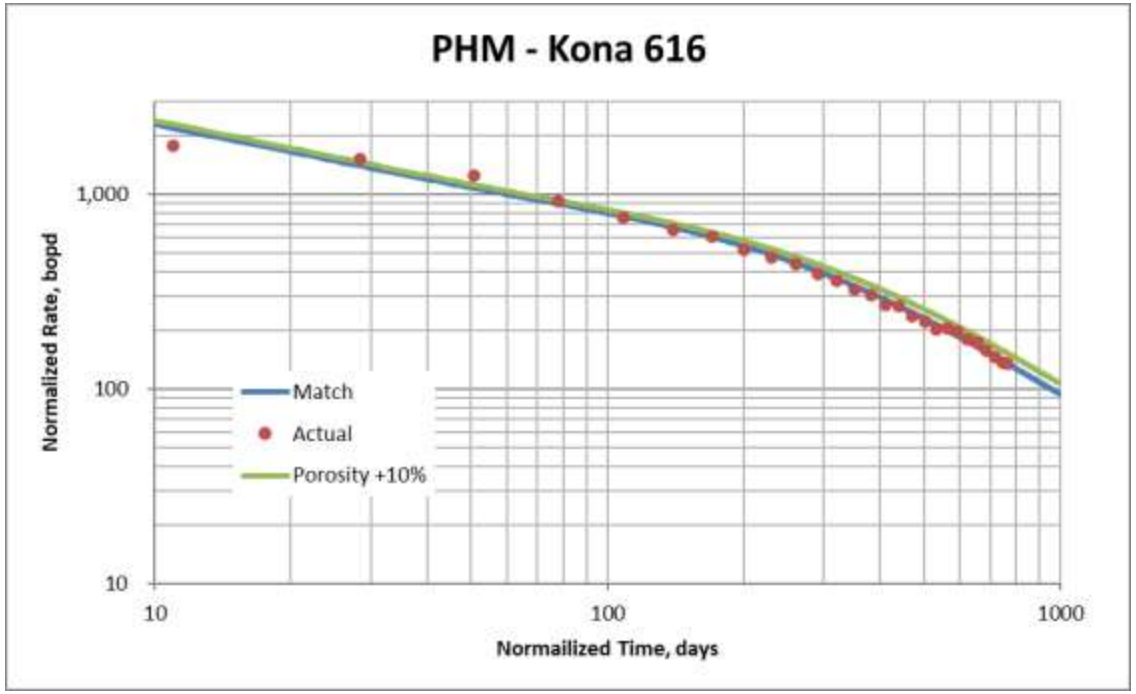
Normalization

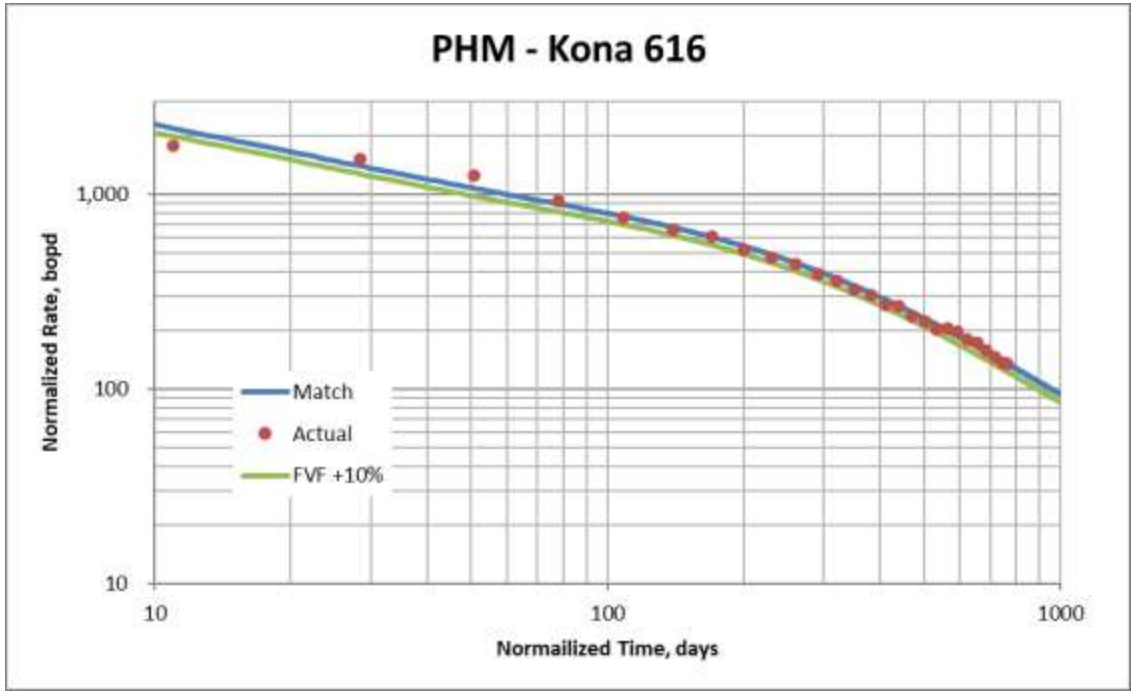
- Normalized rate:
  - $Qn = \frac{Q}{(Pi - Pwf)} * (\mathrm{Pi} - \mathrm{Pn})$
  - Where:
    - Qn = Normalized Rate
    - Q = Actual Rate
    - Pi = Initial Pressure
    - Pwf = Flowing pressure
    - Pn = Normalized flowing pressure (the flowing pressure the model will be produced at)

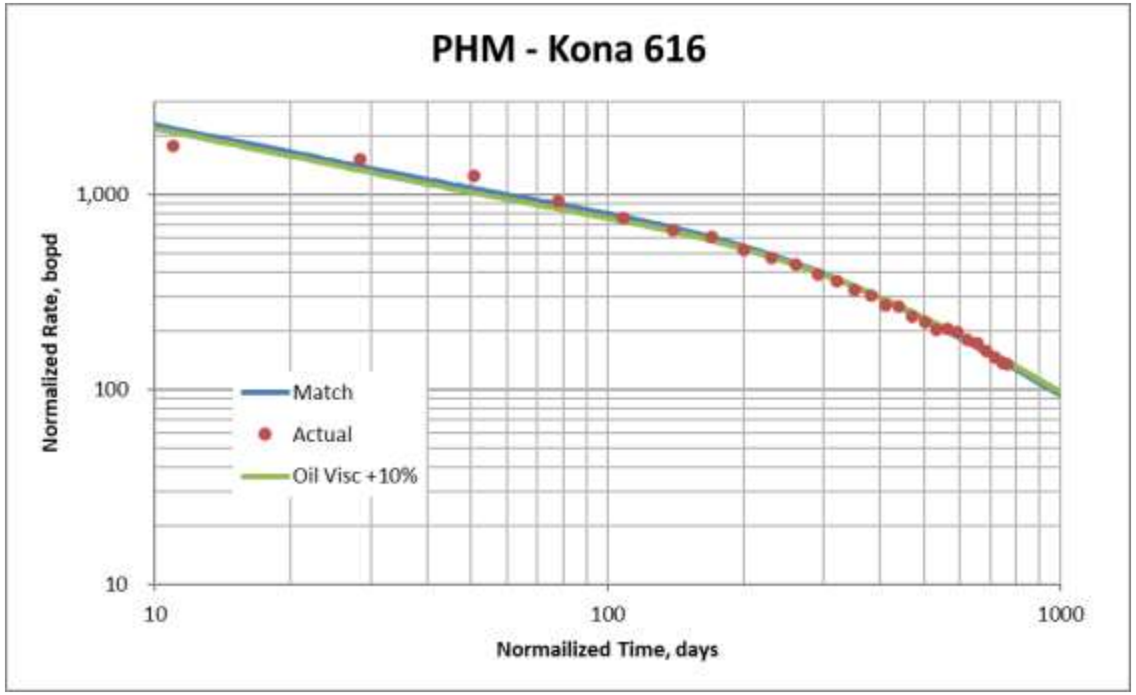
- Normalized time:
  - $\Delta tn = \frac{Q}{Qn}$
  - Where:
    - $\Delta tn =$ Normalized incremental time
    - Q = Actual Rate
    - Qn = Normalized rate

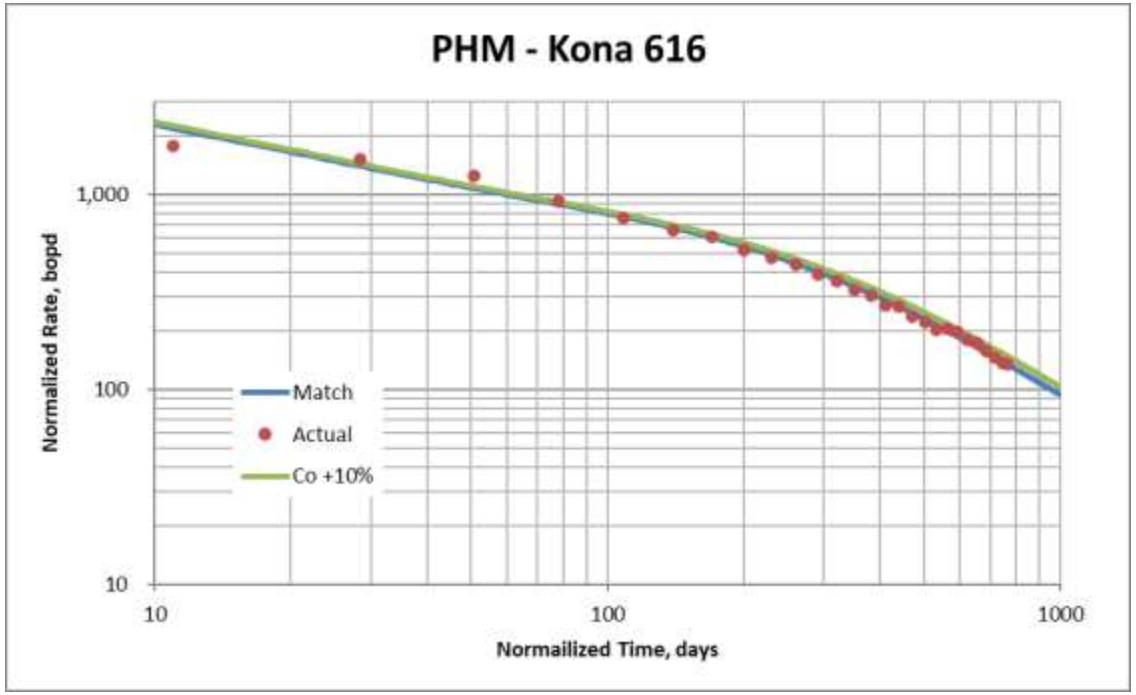
Reservoir & Fluid Properties used

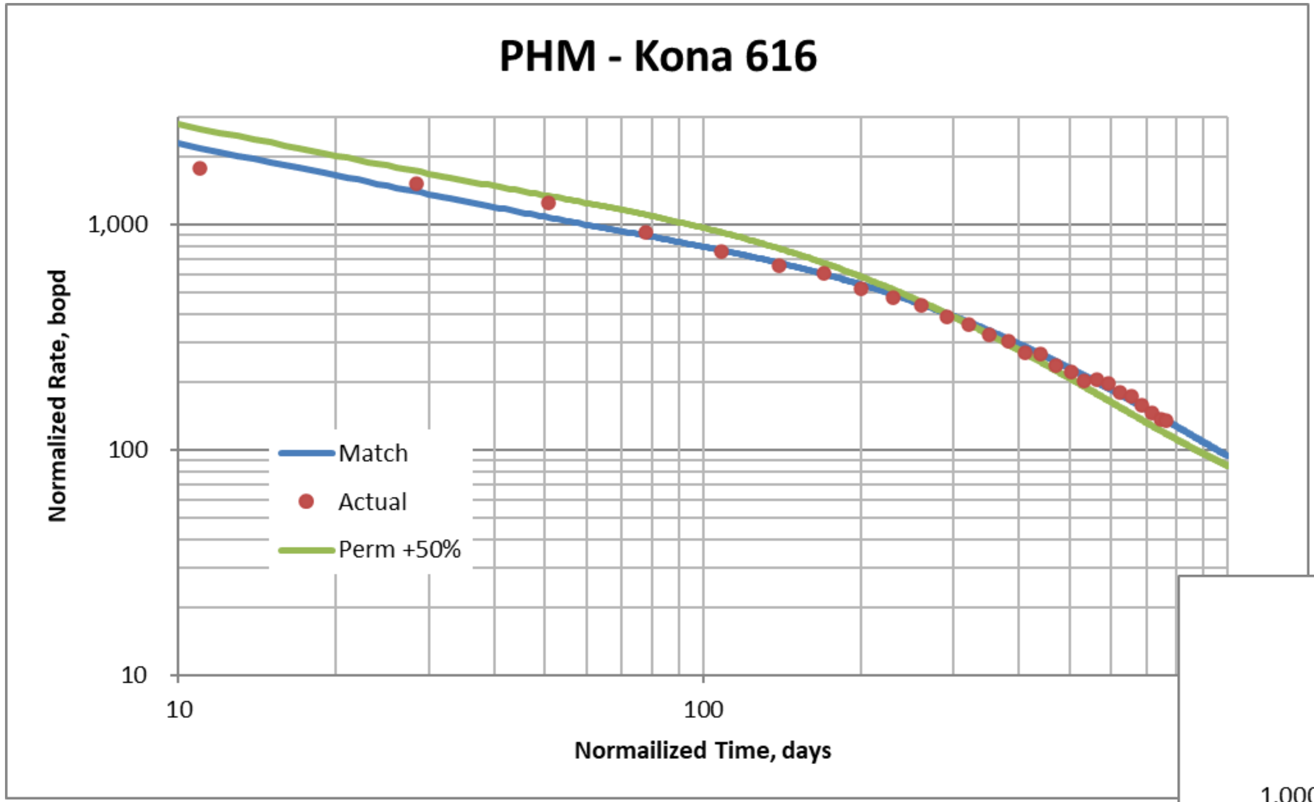
- Formation Properties
  - Porosity = 8.2%
  - S_w = 33%
  - $C_f = 4x10^{-6}$ psi^{-1}
  - Net Pay
    - Varies by match on Kona Pad
    - 169 feet on Dunn Pad (Codell – Nio B)
- Fluid Properties
  - Bo = 2.25 RB/STB
  - Oil Visc = 0.12 cps
  - $C_o = 43x10^{-6}$ psi^{-1}
  - $C_w = 3.6x10^{-6}$ psi^{-1}

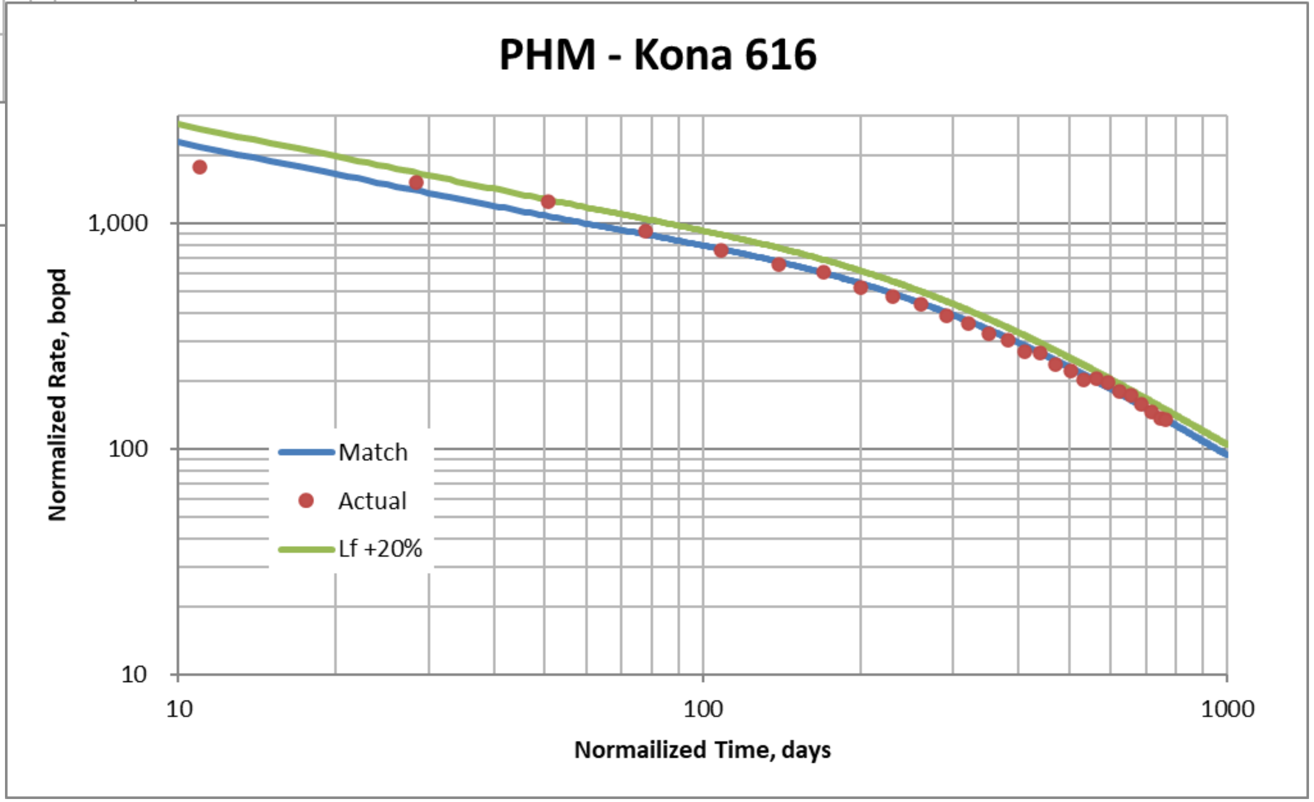

PHM - Kona 616
Normalized Rate, bopd
Normailized Time, days
Match
Actual
Porosity +10%
10
100
1,000
1000


PHM - Kona 616
Normalized Rate, bopd
Normailized Time, days
Match
Actual
FVF +10%
10
100
1,000
1000


PHM - Kona 616
Normalized Rate, bopd
Normailized Time, days
Match
Actual
Oil Visc +10%
10
100
1,000
1000


PHM - Kona 616
Normalized Rate, bopd
Normailized Time, days
Match
Actual
Co +10%
10
100
1,000
1000


PHM - Kona 616
Normalized Rate, bopd
1,000
100
10
10
100
Normailized Time, days
Match
Actual
Perm +50%


PHM - Kona 616
Normalized Rate, bopd
1,000
100
10
10
100
1000
Normailized Time, days
Match
Actual
Lf +20%

Observing the end of early-time linear flow

The 7I-321 has the closest offsets on Dunn Pad

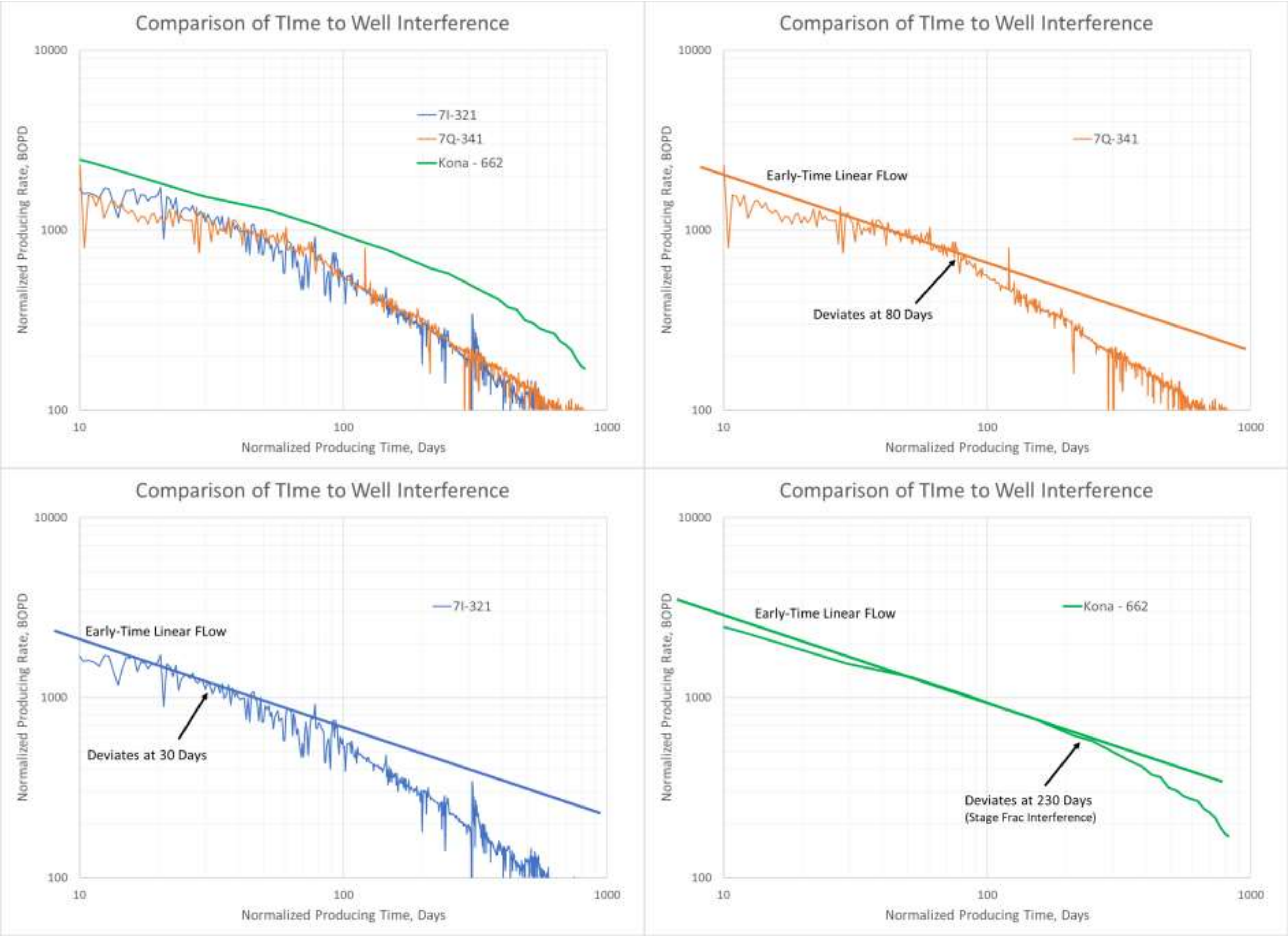
The 7Q-341 has the furthest offsets on the Dunn Pad

The Kona-662 has furthest offsets on Kona Pad

All of the Dunn Pad wells exhibit the end of early-time linear flow before they should

Dunn Pad wells are too close together

Kona Pad wells are most likely too far apart

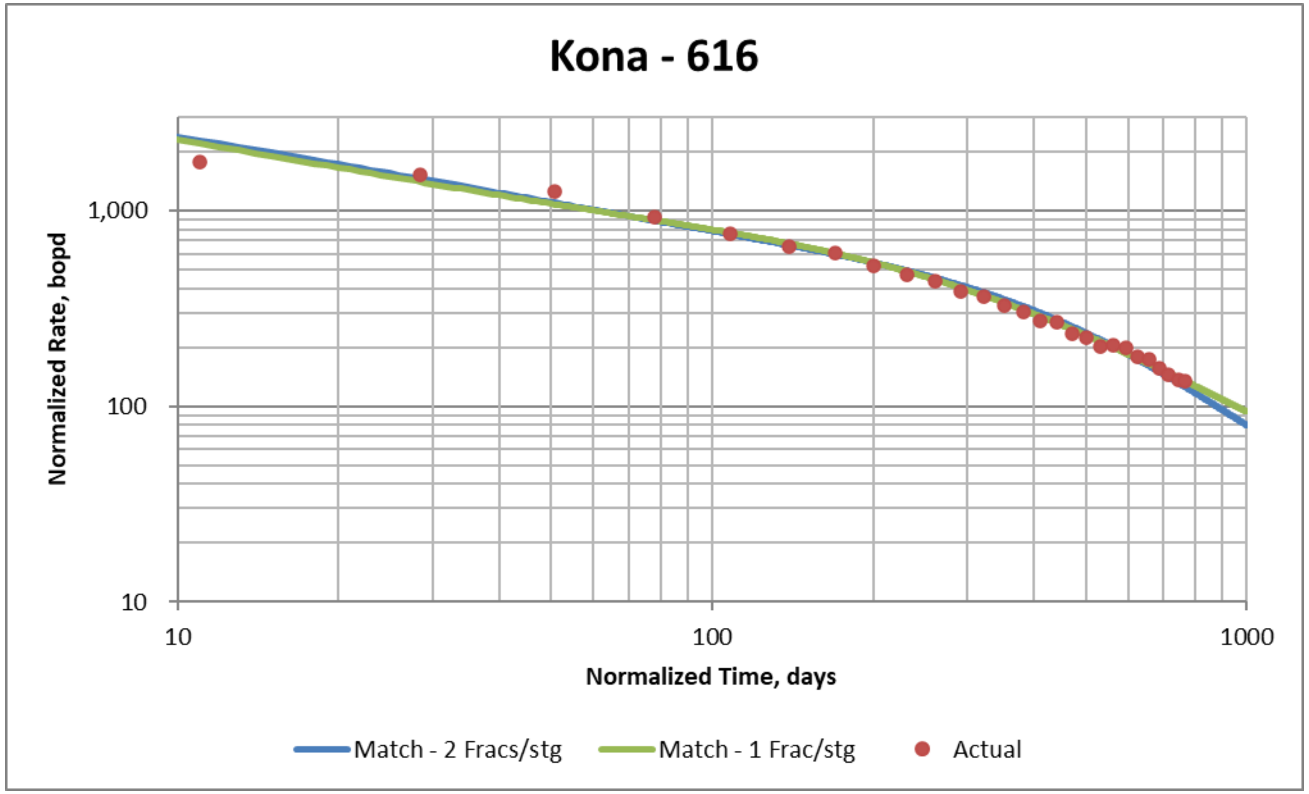


Results Summary

Pad	Well #	Compl Date	IP540 Oil	540BO / ft	end depth	start depth	length	Sand #	Sand #/ft	Fluid	Bbbl/ft	#/bbl	stages	stage length	Zone	#/stage	Contacted Net Pay	Fracs/Stg	Perm	Lf
Kona	a19-685	Jan-18	360.2	34.6	18,661	8,242	10,419	29,152,250	2,798	976,740	94	0.71	44	237	Nio C	662,551	105	2	300	280
Kona	a19-670	Jan-18	360.8	33.9	18,227	7,576	10,651	29,152,250	2,737	976,740	92	0.71	44	242	Nio B	662,551	105	2	480	230
Kona	a19-662	Dec-17	348.7	35.2	17,412	7,502	9,910	29,616,188	2,989	978,516	99	0.72	44	225	Codell	673,095	115	2	220	280
Kona	a19-646	Dec-17	317.8	29.6	18,039	7,312	10,727	31,382,201	2,926	1,021,939	95	0.73	44	244	Nio C	713,232	95	2	400	230
Kona	a19-636	Nov-17	282.6	25.9	18,236	7,327	10,909	39,844,907	3,652	1,330,817	122	0.71	62	176	Nio B	642,660	95	2	220	210
Kona	a19-624	Nov-17	229.0	25.4	16,321	7,317	9,004	34,854,455	3,871	1,118,923	124	0.74	78	115	Codell	446,852	95	1	300	215
Kona	a19-616	Nov-17	278.3	26.2	17,752	7,112	10,640	39,469,757	3,710	1,282,699	121	0.73	91	117	NioC	433,734	95	1	350	200
Dunn	7I-201	May-17	215.4	22.3	16,724	7,078	9,646	10,830,000	1,123	193,304	20	1.33	57	169	Nio B	190,000	169	2	300	85
Dunn	7I-321	May-17	185.8	19.2	16,769	7,103	9,666	10,434,000	1,079	196,561	20	1.26	57	170	NioC	183,053	169	2	300	75
Dunn	7I-221	Apr-17	191.4	20.0	16,679	7,088	9,591	10,595,000	1,105	191,756	20	1.32	56	171	Nio B	189,196	169	2	300	75
Dunn	7L-341	May-17	181.5	18.8	16,768	7,098	9,670	10,161,500	1,051	195,942	20	1.23	57	170	NioC	178,272	169	2	300	75
Dunn	7L-201	May-17	163.3	16.8	16,700	6,964	9,736	10,490,320	1,077	191,525	20	1.30	57	171	Nio B	184,041	169	2	300	75
Dunn	7L-301	May-17	208	21.5	16,760	7,076	9,684	10,842,000	1,120	198,058	20	1.30	57	170	NioC	190,211	169	2	300	85
Dunn	7L-221	May-17	174.5	18.2	16,679	7,088	9,591	10,595,000	1,105	191,756	20	1.32	56	171	Nio B	189,196	169	2	300	75
Dunn	7Q-341	May-17	182.9	19.0	16,775	7,158	9,617	9,551,400	993	196,874	20	1.16	47	205	NioC	203,221	169	2	300	85
Dunn	7Q-241	May-17	171	17.6	16,827	7,129	9,698	10,268,700	1,059	198,393	20	1.23	57	170	Nio B	180,153	169	2	300	70
Dunn	7Q-301	May-17	175.8	18.2	16,943	7,269	9,674	10,373,000	1,072	196,237	20	1.26	57	170	NioC	181,982	169	2	300	75
Dunn	7Q-221	May-17	189.4	19.5	17,007	7,284	9,723	10,732,190	1,104	196,881	20	1.30	57	171	Nio B	188,284	169	2	300	85

Example Match – Fracs/Stage

- Kona 616
  - 91 stages
  - 117’ stage spacing
- Matched - 1 Frac/stg
  - Perm = 350 nD
  - Lf = 200 feet
- Matched – 2 Fracs/stg
  - Perm = 50 nD
  - Lf = 275 feet



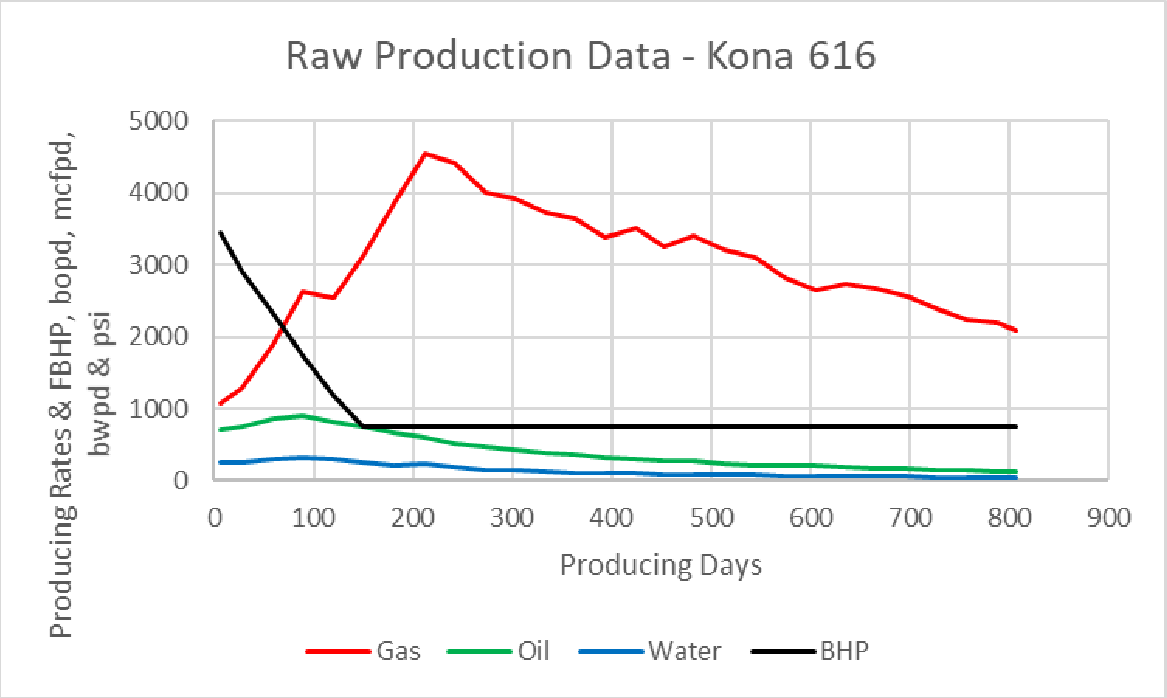
DJ Basin Operator
Future Pad Completion Optimization

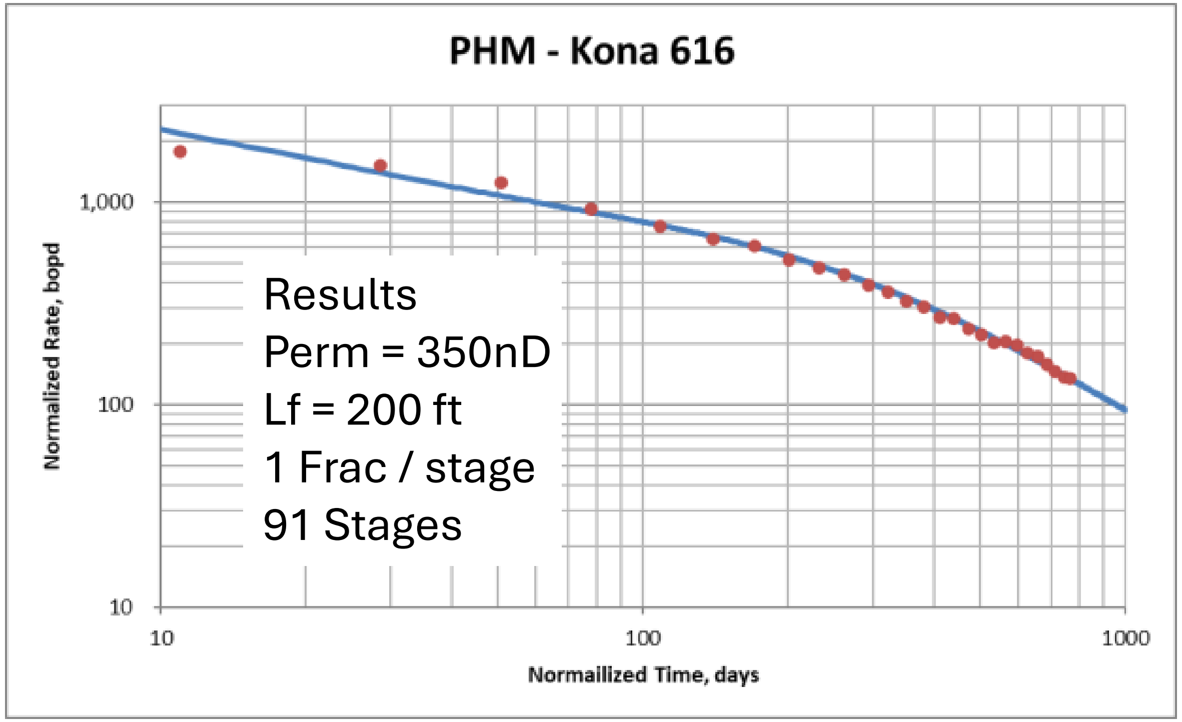
Schubarth Inc

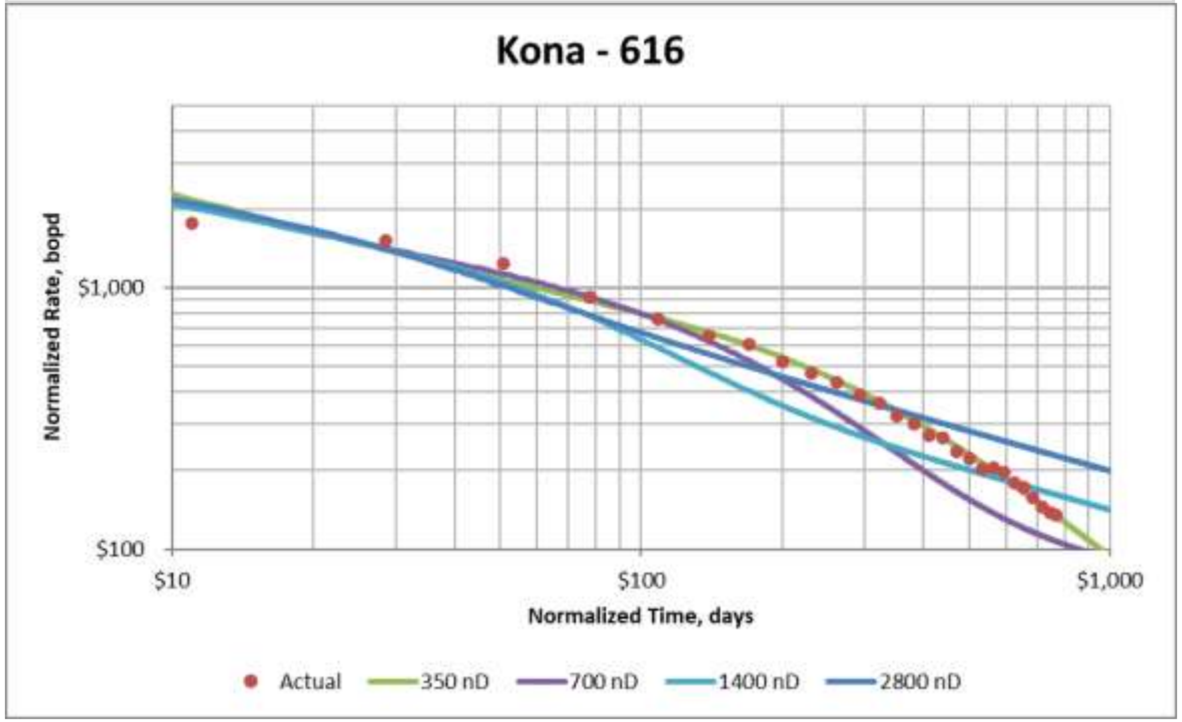
Sugar Land, TX

Example Production History Match

- Raw production data and Flowing Surface Pressures
- Calculate FBHP
- Normalize Producing Rates and Producing Times
- Production History Match Normalized data with model

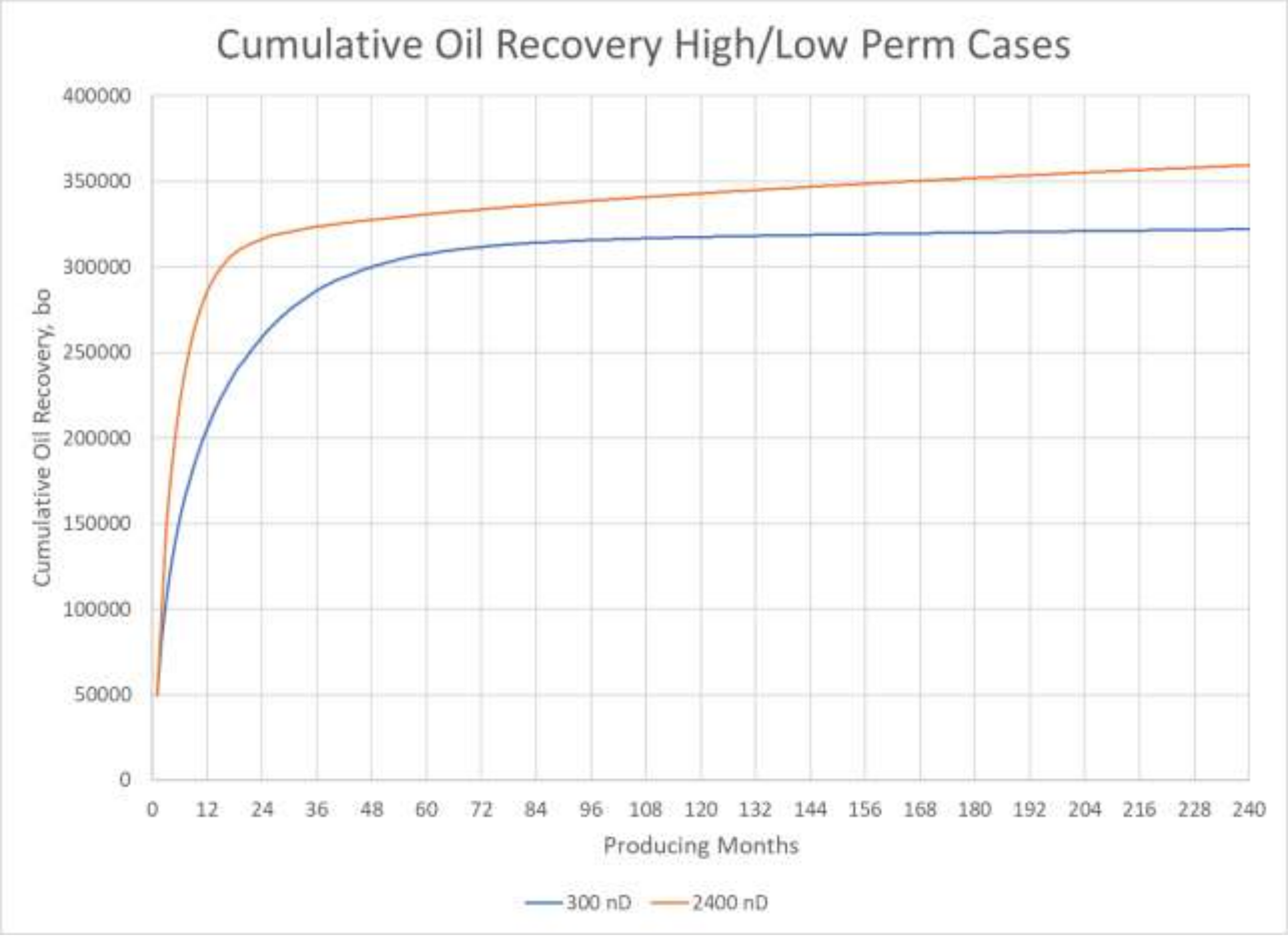


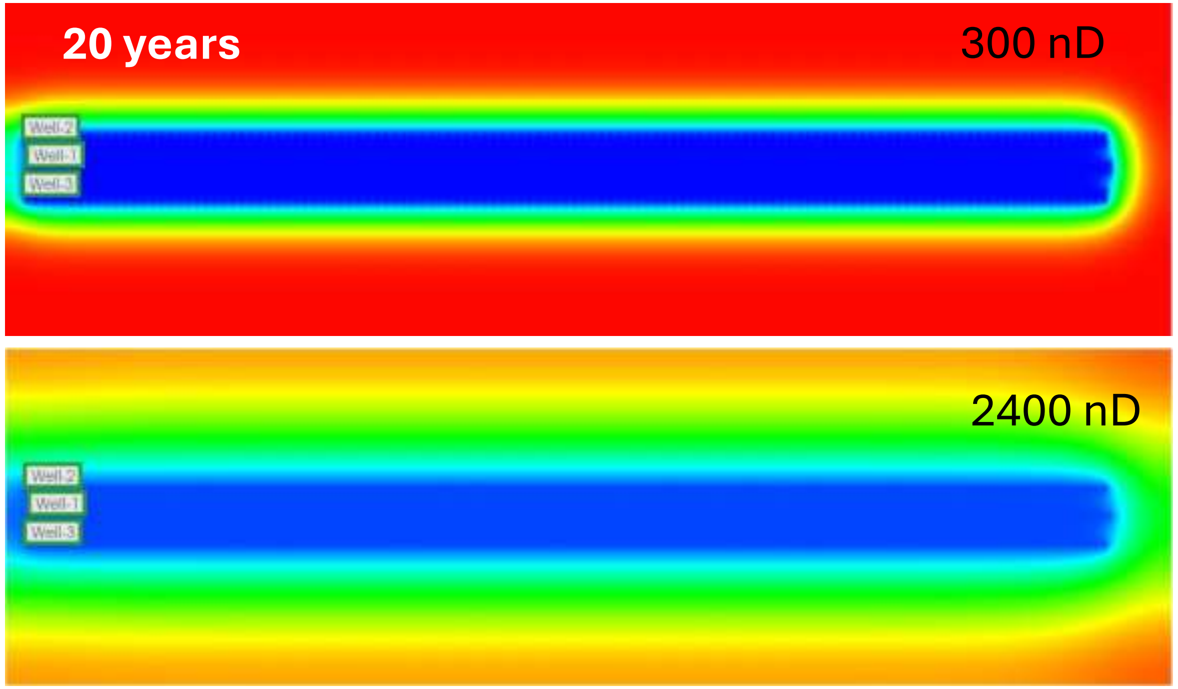




Perm Investigation

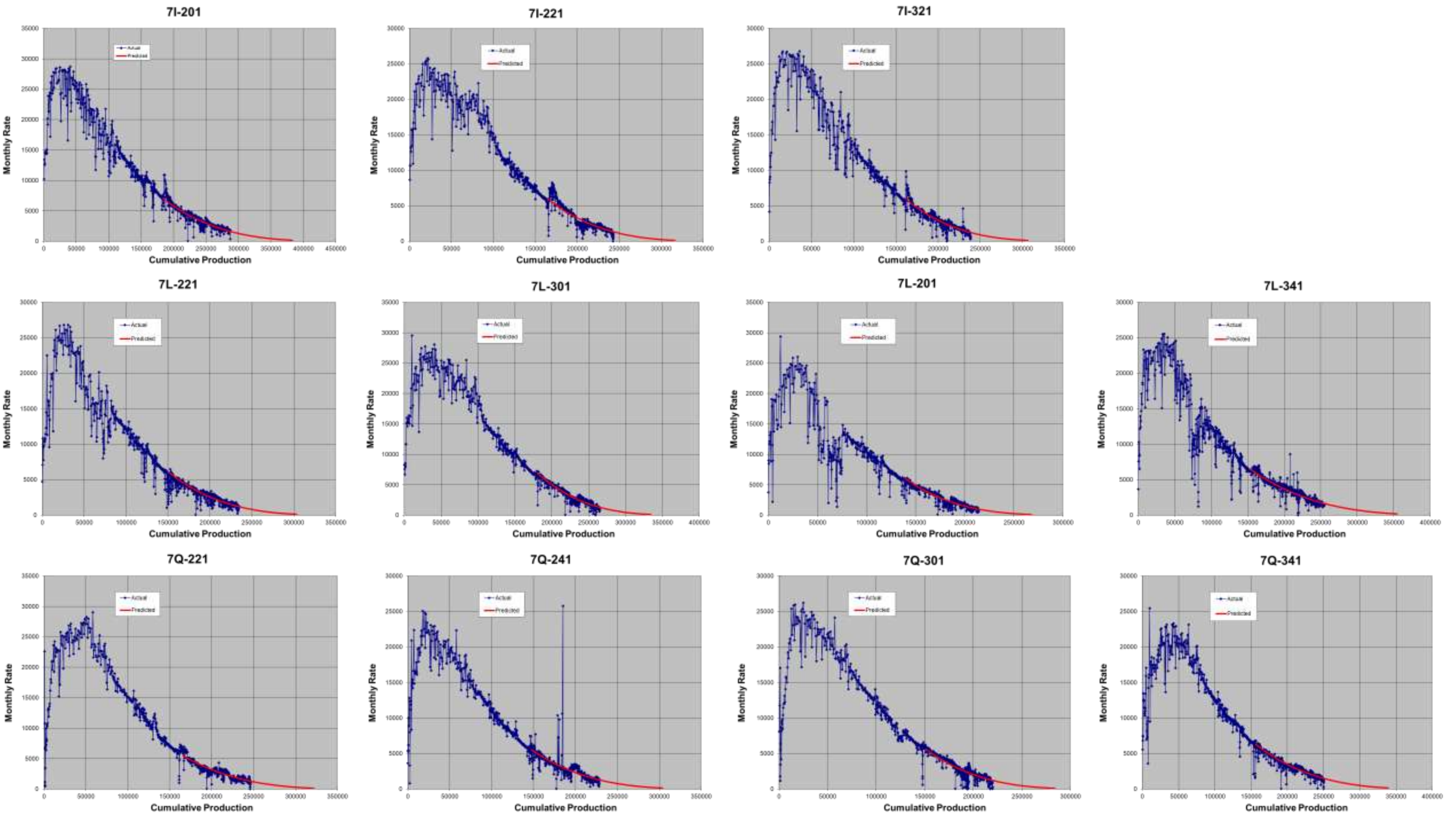
- Higher perm – shorter frac simulations match early time, not middle or late time
- Pressure transients from high perm simulations investigate too deep into reservoir

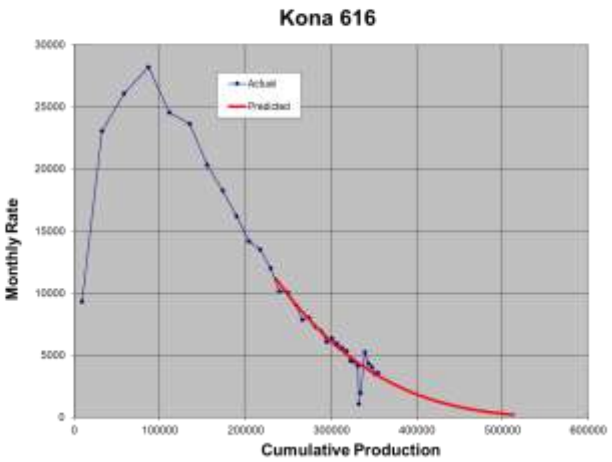


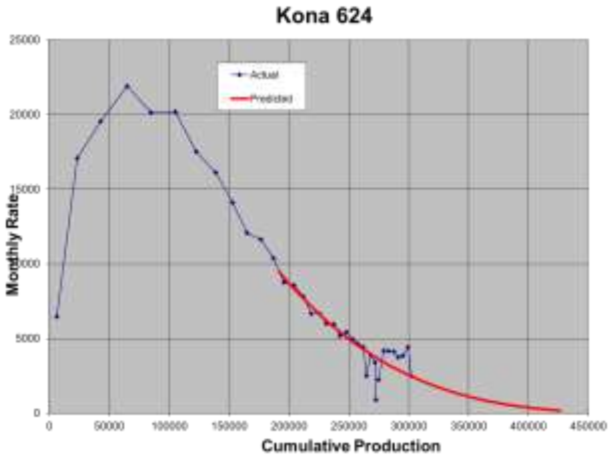


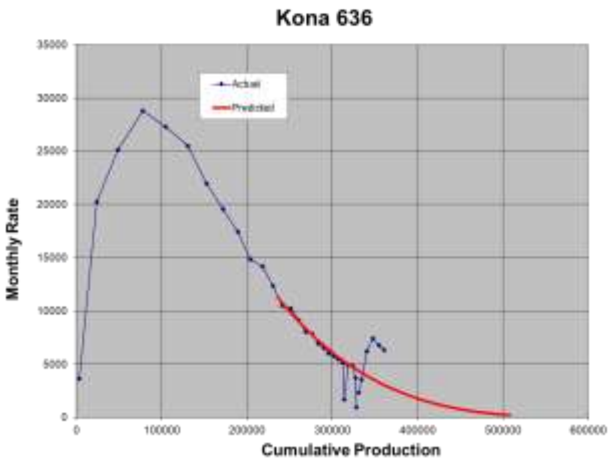
Resolve Net Pay Completed Issue on Dunn Pad from Phase 1 – Step 1

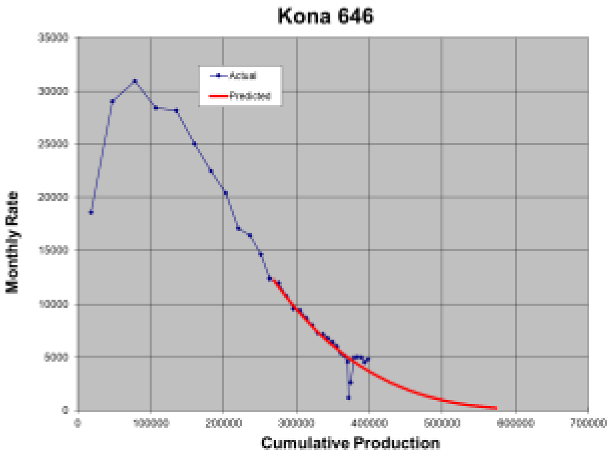
- Perform EUR evaluation for all wells
- Dunn Pad average EUR is 319 mbo
- Performed simulation runs to match EUR

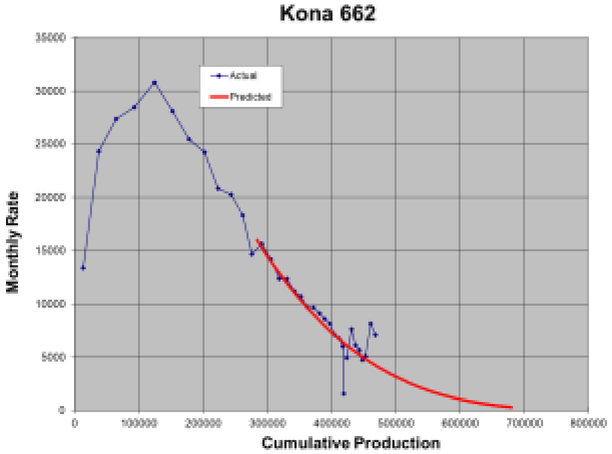

7I-201
7I-221
7I-321
7L-221
7L-301
7L-201
7L-341
7Q-221
7Q-241
7Q-301
7Q-341
Monthly Rate
Cumulative Production
Actual
Predicted

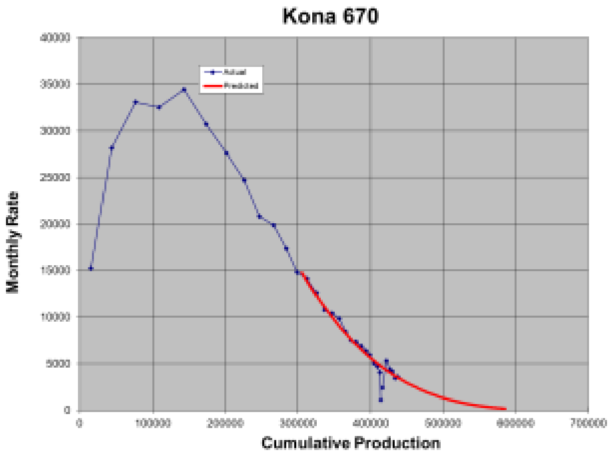

Kona 616
Actual
Predicted
Monthly Rate
Cumulative Production

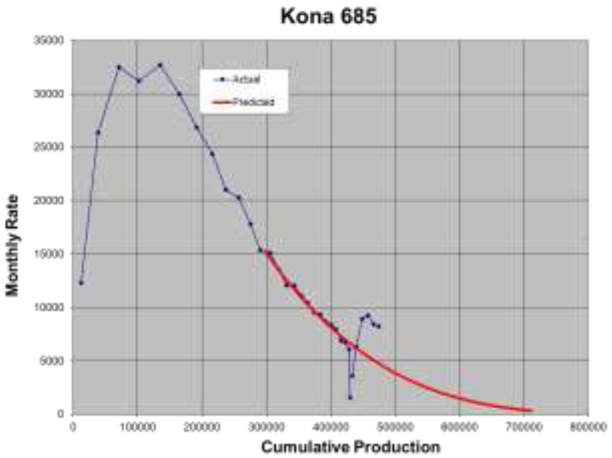

Kona 624
Actual
Predicted
Monthly Rate
Cumulative Production


Kona 636
Actual
Predicted
Monthly Rate
Cumulative Production


Kona 646
Actual
Predicted
Monthly Rate
Cumulative Production


Kona 662
Actual
Predicted
Monthly Rate
Cumulative Production

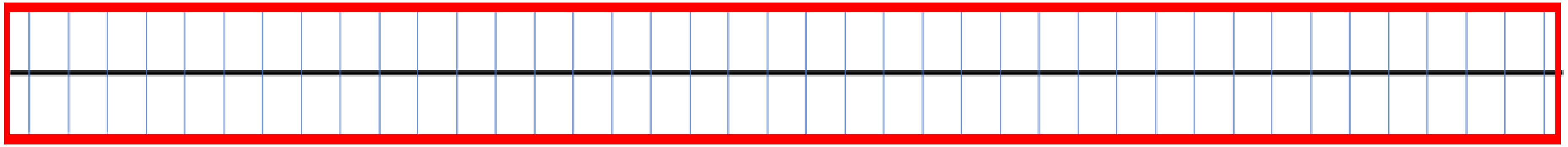

Kona 670
Actual
Predicted
Monthly Rate
Cumulative Production


Kona 685
Actual
Predicted
Monthly Rate
Cumulative Production

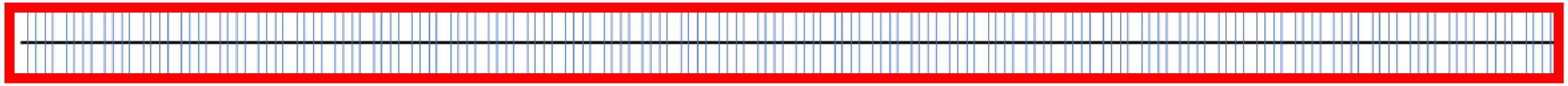
Spending CapEx on Beneficial Efforts

Lf is dependent on the size of the stage pumped
SRV is dependent on Lf & Lateral Length
EUR is proportional to SRV

Fractured Area = SRV



More stages create more fracs along the lateral
More stages of smaller size may result in higher #/ft values but smaller SRVs
This is what happened to the Kona Pad

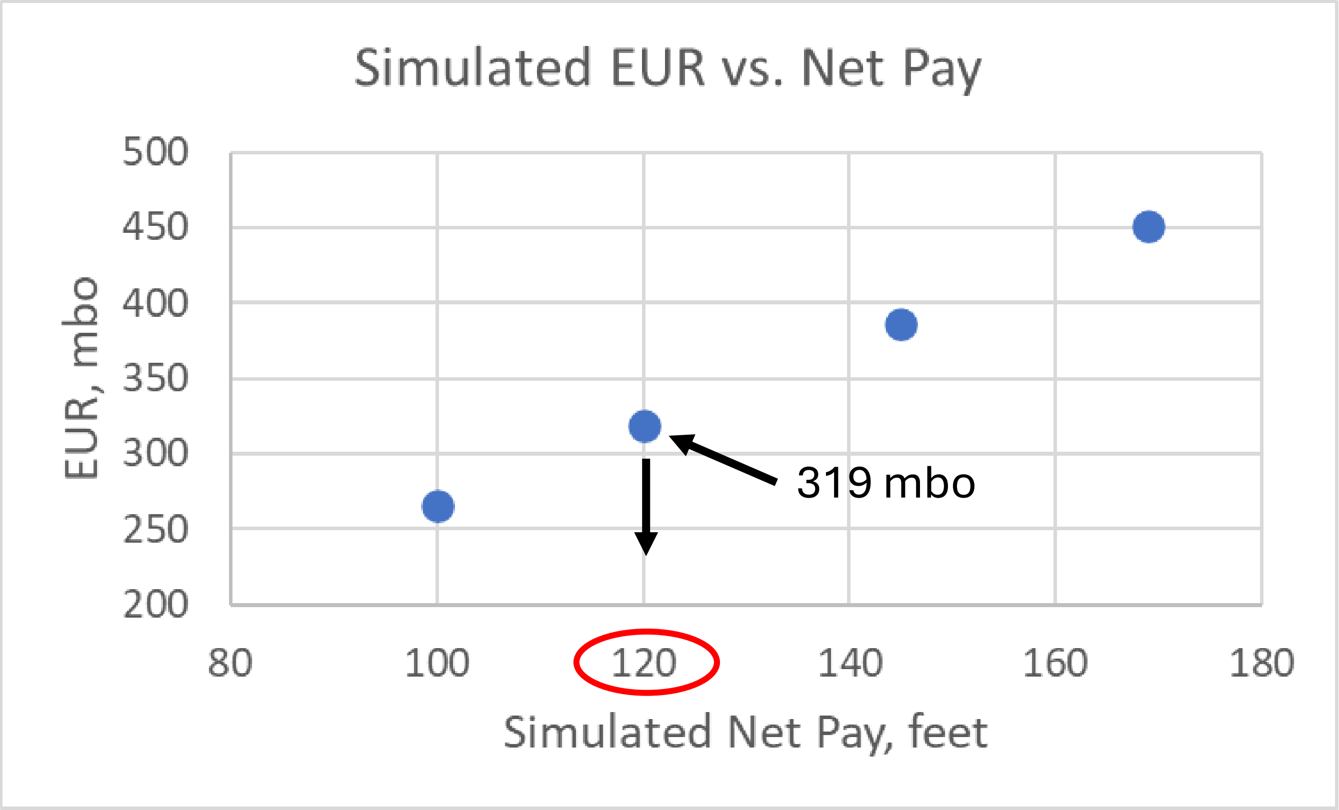


EURs for Existing Wells

- 11 Dunn wells average 319 MBO
  - The highest EUR well is on the western edge where the offset well is the furthest away
  - The distance between wells averages about 250 feet
  - Using finite difference simulation and the estimated reservoir and completion properties from Phase 1 we produce too much oil from a bound well
  - Net pay was varied to compare recoveries
  - It was determined that the Net Pay being contacted by the Dunn wells was actually 120 feet, not the 169 feet estimated from Phase 1
  - The following graph shows the simulation results

Bounded Well Simulation – Dunn Lease

- Simulating a bounded well finds that inter-well interference occurs rapidly as seen in the production data
- EUR for these wells is controlled by their proximity to each other

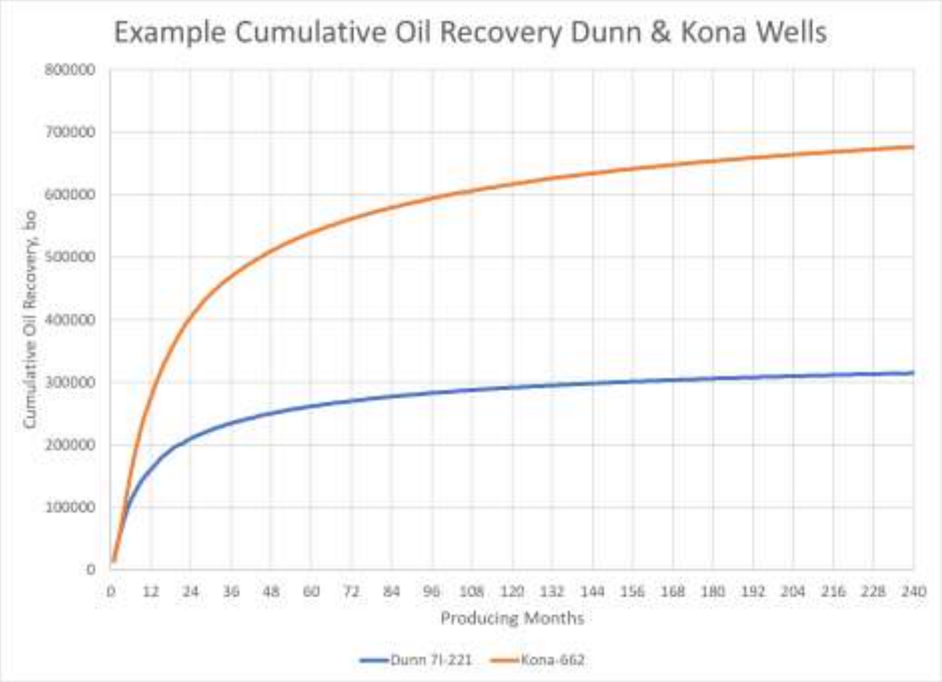


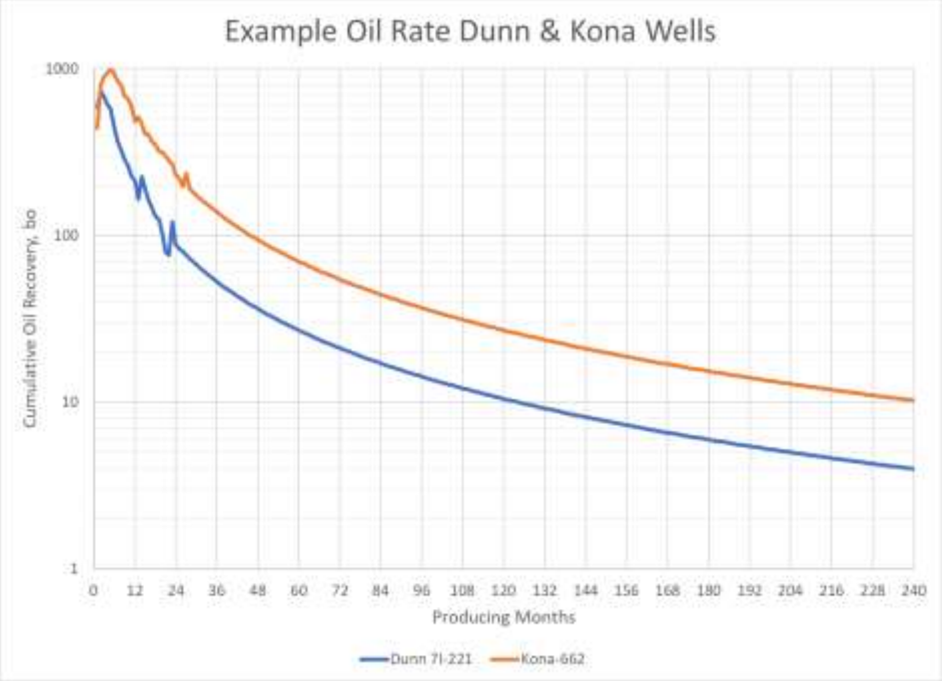
Comparison between Hungenberg & Kona Stage Costs

- Estimating the cost of Kona Fracs
  - Ratio time dependent costs by fluid volumes
  - Ratio fluid volume costs by fluid volumes
  - Calculate prop volume costs
  - Fixed costs per stage included

		Future	Kona-662
Frac Crew	($/stage)	$ 6,500	$ 17,000
FR	($/stage)	$ 1,811	$ 6,000
Gel	($/stage)	$ -	
Biocide	($/stage)	$ 600	$ 2,200
Breaker	($/stage)	$ 239	$ 877
Acid	($/stage)	$ 370	$ 370
40/70	($/stage)	$ 2,970	
30/50	($/stage)	$ 2,871	
100 mesh	($/stage)	$ 660	$ 19,110
Proppant Handling	($/stage)	$ 2,464	$ 7,134
Pump Down	($/stage)	$ -	
Fuel	($/stage)	$ 2,505	$ 9,185
Fresh Water	($/stage)	$ 1,860	$ 6,820
Recycled Water	($/stage)	$ -	
Supervision	($/stage)	$ 361	$ 1,325
Wireline	($/stage)	$ 2,250	$ 2,250
Plug	($/stage)	$ 700	$ 700
Disolavable Plugs	($/stage)	$ 77	$ 77
Wellhead	($/stage)	$ 1,538	$ 5,641
WCU	($/stage)	$ 107	$ 392
Water Transfer	($/stage)	$ 271	$ 992
Drillout	($/stage)	$ 2,776	$ 2,776
Rentals	($/stage)	$ 1,119	$ 4,103
Frack Support	($/stage)	$ -	
ACM	($/stage)	$ 4,558	$ 4,558
Frack Tanks	($/stage)	$ 193	$ 708
Labor and Services	($/stage)	$ 829	$ 3,039
Water Heating	($/stage)	$ 783	$ 2,873
Water Recycle	($/stage)	$ 210	$ 770
Total Stage	($/stage)	$ 38,622	$ 98,900

- Economic comparison between Dunn & Kona wells
- Dunn 7I-221
  - EUR = 316 mbo
  - Well cost = $3.96 Million
    - 56 stages @ 36,450/stage
  - Cumulative Cash Flow = $16.46 million
  - NPV@10% = $12.40 million
  - ROI = 5.16
- Kona 662
  - EUR = 679 mbo
  - Well cost = $6.27 million
    - 44 stages @ $98,900/stage
  - Cumulative Cash Flow = $24.17 million
  - NPV@10% = $18.66 million
  - ROI = 4.86





CMG Simulation Inputs

- Simulations performed using single phase
- PhiSo used as input porosity
- Wells produced at constant Pwf
  - This produces results that favor tighter well and stage spacing
- Fracs input at 2 per stage
- 10k Lateral Lengths
- Use center bounded well production for well spacing study

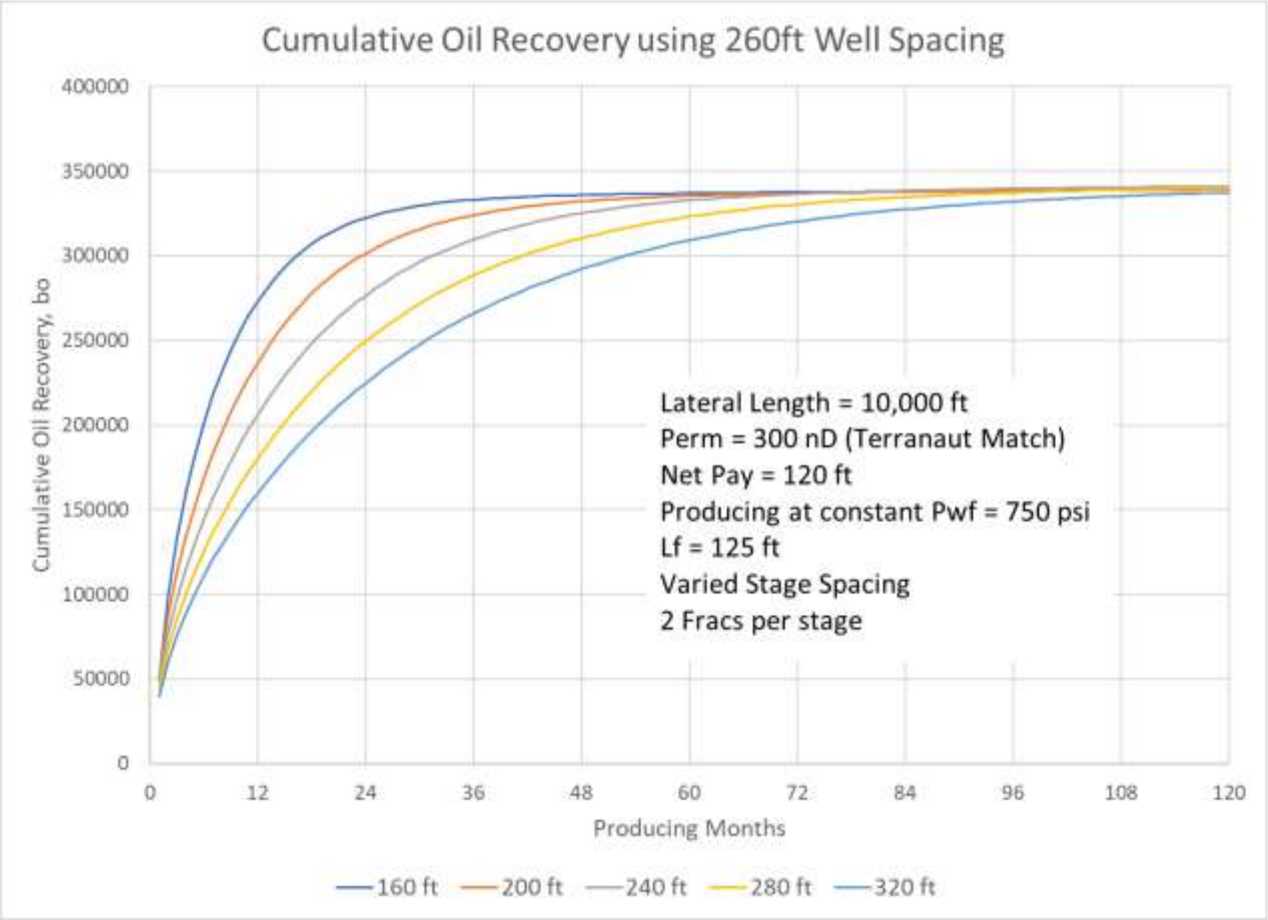
CMG Input Parameters		
Net Pay	120	ft
Lateral Length	10000	ft
Fracs/stage	2	
Porosity	0.055	
Initial Pressure	4500	psi
Pwf	750	psi
FVF	2.25	rb/stb
Viscosity	0.12	cps
Fluid Compressibility	4.30E-05	psi-1
Perm	varies	
Lf	varies	
Producing Life	20 years	
Cell dimensions	10	ft
Relative Perms	not used	

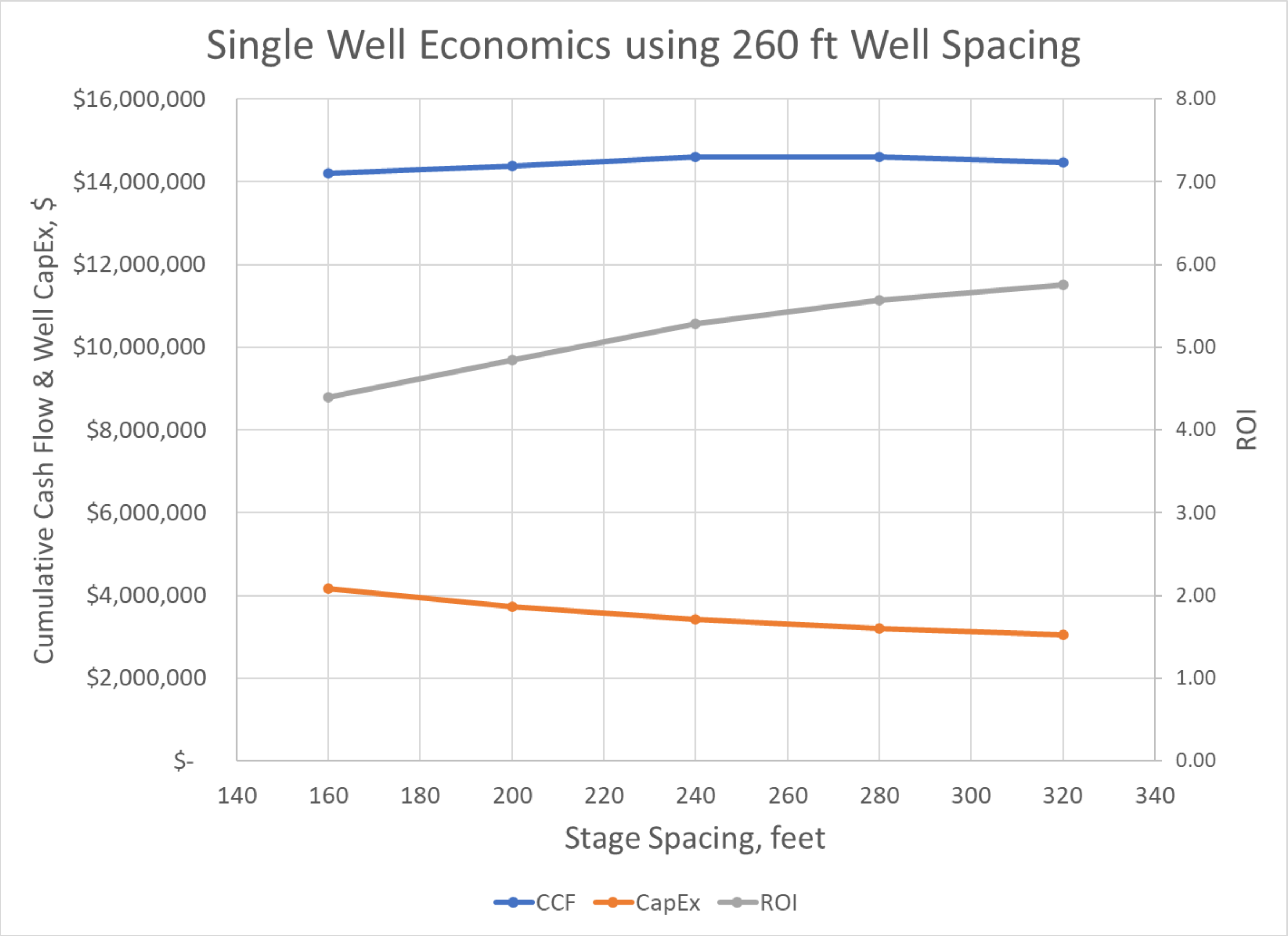
Future Stage Spacing Simulation

- Planned well spacing for the Future lease has wells averaging about 260 feet apart
- Simulations were performed using 260 ft well spacing between a center bounded well and offsetting wells
- Stage spacing was then varied using 160, 200, 240 & 320 feet
- All stage spacing scenarios recovered the same 20year oil
- Wider stage spacing recovered oil more slowly
- Economics were run to determine the resulting NPV & ROI for each scenario

Future Completion Optimization

- Used predicted production curves from Well Spacing runs to establish production for Future lateral lengths
- Compared current design using 200 ft stage spacing to 240 ft spacing




Single Well Economics using 260 ft Well Spacing
Cumulative Cash Flow & Well CapEx, $
$16,000,000
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$-
ROI
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
140
160
180
200
220
240
260
280
300
320
340
Stage Spacing, feet
CCF
CapEx
ROI

Recommendation

- Increase Stage Spacing from 200 to 240 feet
- Complete 5 wells with 7951 ft laterals & 4 wells with 9711 ft laterals
- Reduce stage count
  - On 7951 ft lateral wells from 39 to 33 stages @$36,450/stage (5 wells)
  - On 9711 ft laterals wells from 48 to 40 stages @$36,450/stage (4 wells)
- Reduces CapEx for 9 wells by $2.26 million
- Increases ROI from 4.54 to 4.85
- Oil Recovery for both cases is 2.7 mmbo