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Shale Oil Review, US Lower 48

When **insight** *matters*.™

January 2014

US Shale Oil Growth and Profitability Study

The Study Focused on the Following Questions:

- Are shale oil developments in the US profitable?
- Can major new entries still be made that are economic?
- Are the major US shale oil basins mature or still growing in scope and optimization opportunity?

Four of the premier shale oil basins were studied:

- Williston – Bakken formation as the primary development interval
- Gulf Coast - Eagle Ford formation as the primary development interval
- DJ Wattenberg – Niobrara formation as the primary development interval
- Permian – Wolfcamp formation as the primary development interval

Observations Common to all Four Basins:

- They are highly profitable starting from the development phase and moving forward
- They continue to grow in the number of pay intervals in the vertical section and modify aerial extent.
- They continue to show improving development metrics: downspacing, IPs & EURs, capital costs, operating expense, and mid stream capacity
- They economically support new entry acquisition costs at current transaction mulitples.

Continued Asset Improvement & Geologic Upside

All Four Basins Show Improving Performance

- Rates: Increasing
- EURs: Increasing
- Costs: Decreasing for wells and completions
- Time from spud to first oil is decreasing
- Midstream capacity & regional export is increasing

All Four Basins Continue to Develop Additional and New Geologic Zones

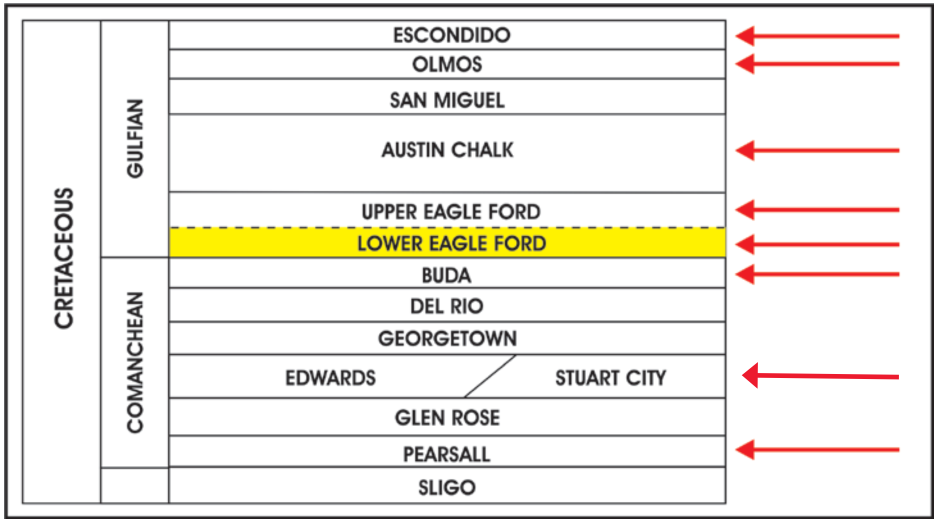
- Vertical extensions to the original interval (additional benches for example)
- Additional / new geologic intervals are producing at economic rates (other than the main basin reservoir)
- Arial modification of the primary zone of interest (Williston: Bakken, DJ Wattenberg: Niobrara, etc)

Eagle Ford: More Intervals, Tighter Spacing & Improved Rates/EURs

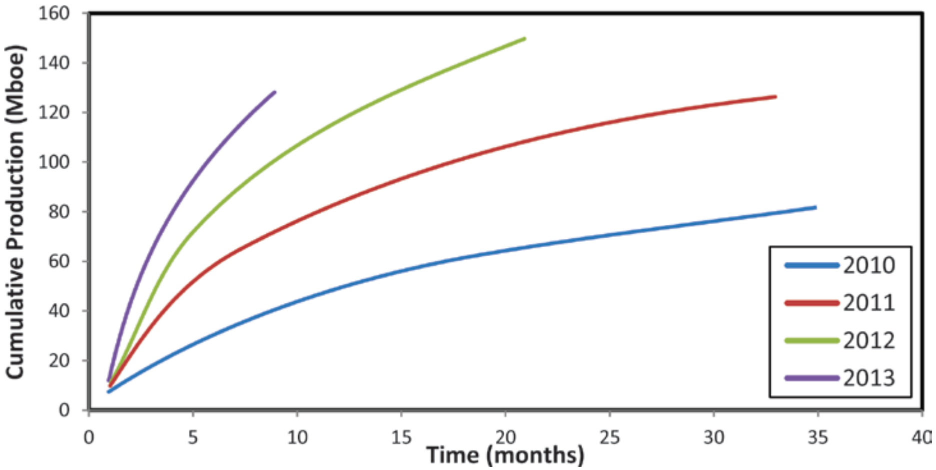
The Gulf Coast continues to grow in the number of pay intervals in the vertical section, adding inventory through downspacing and increased aerial extent.

- Vertical extensions to the original interval (Upper and Lower Eagle Ford)
- Additional / new geologic intervals are producing at economic rates (other than the main Lower Eagle Ford reservoir)
- Improving development metrics: downspacing, IPs & EURs, capital costs, operating expense, and mid stream capacity
    - Target interval and completion optimization have outrun potential performance degradation due to downspacing
- Extending the play aerially to the northeast

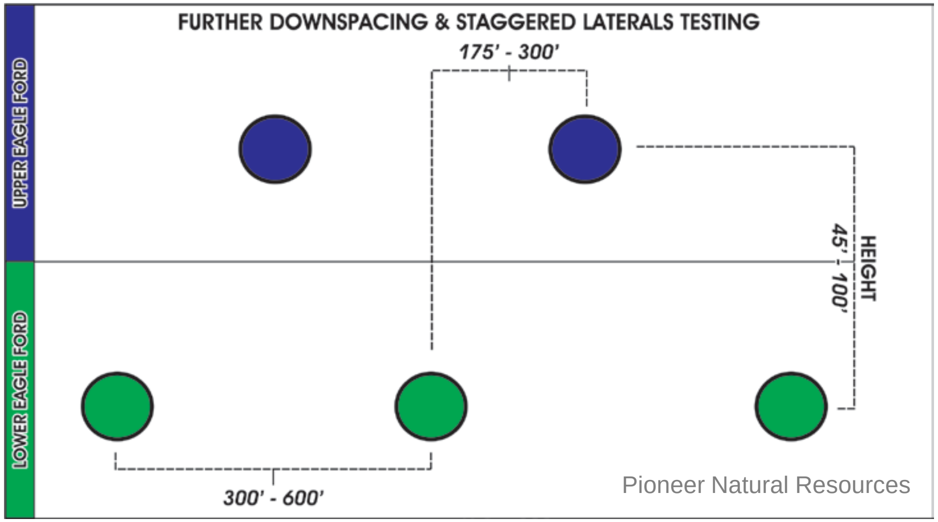
Gulf Coast / Eagle Ford Stratigraphic Column



Well Results Improving Despite Downspacing



Increased Density from 4 to 32 wells per 640 DSU

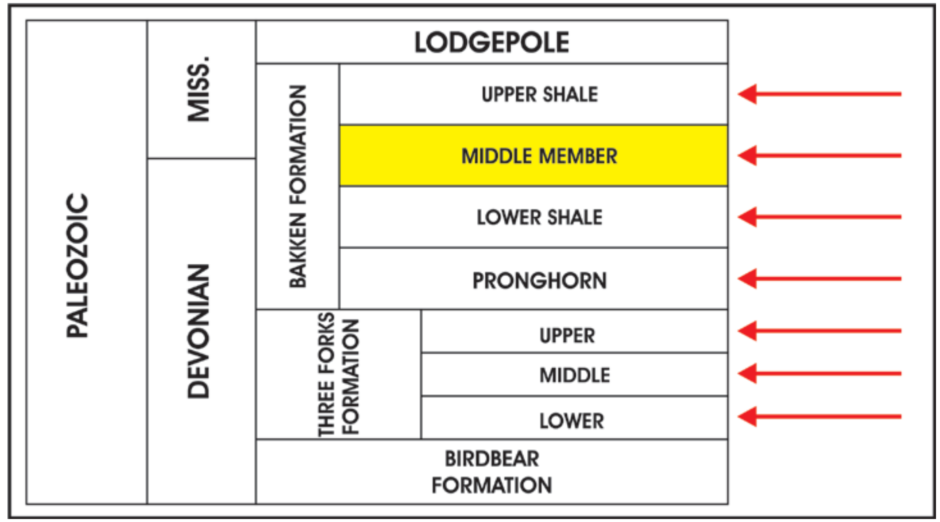


Pioneer Natural Resources

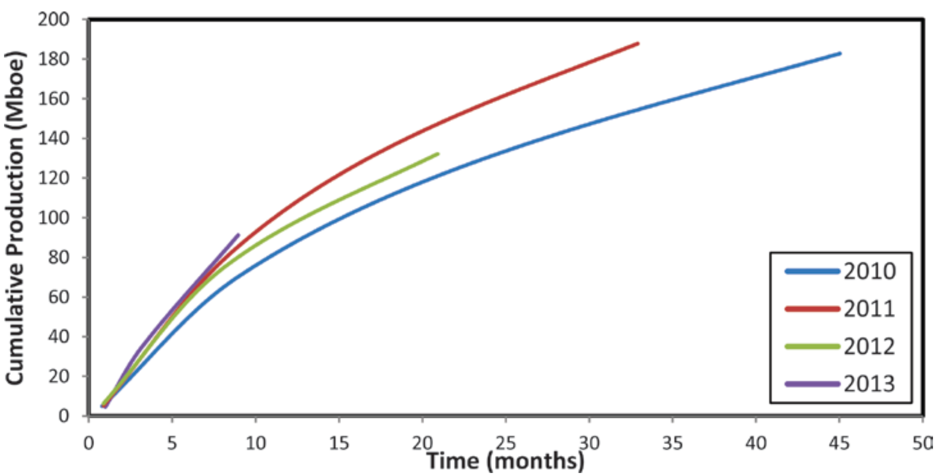
Bakken: More Intervals, Tighter Spacing & Improved Rates/EURs

- CLR producing first multi-interval bench development. Average 1,480 BOEPD from MB & TF1. Average 1,070 BOEPD from TF2 & TF3
- EOG routinely completing MB wells over 2,000 BOPD. Extending these results to the TF1
- Operators such as Whiting are testing the MB up to eight laterals and the Pronghorn up to four laterals per 1,280 acre DSU
- Oasis, Whiting, and Statoil are reporting strong middle Bakken well results in eastern Montana's Roosevelt County, pushing the play further to the West

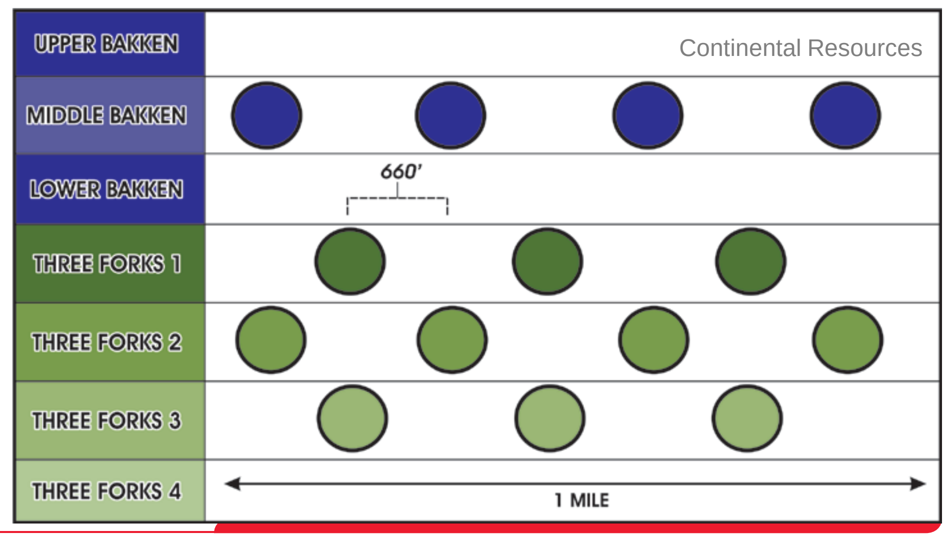
Williston / Bakken



Williston / Bakken: Continental Resources



Williston / Bakken: From 1 to 14 wells per 1280 DSU

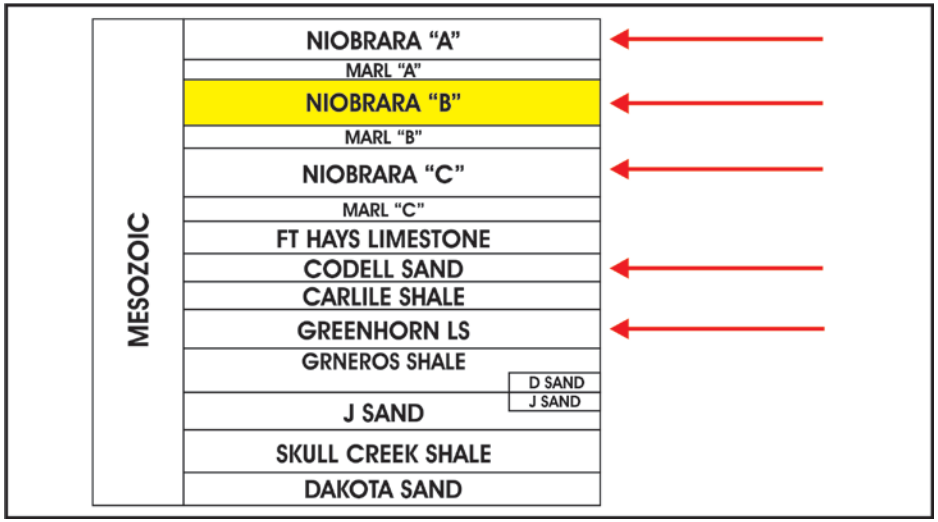


Wattenberg: More Intervals, Tighter Spacing & Improved Rates/EURs

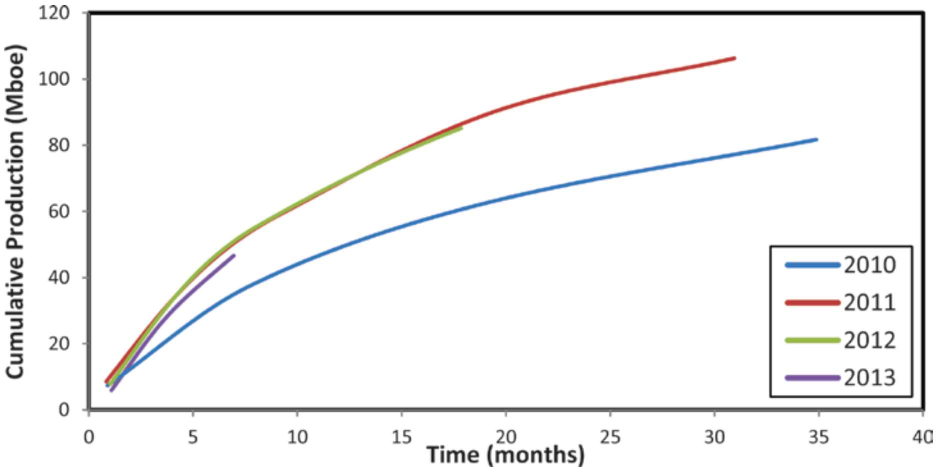
Noble Energy Leading Development

- 9,000 laterals, 750M EUR, 188% BT ROR are being achieved in the main Niabrara B bench
- Play is extending in to northern Colorado's East Pony area
- Full development for the Codell sandstone and emerging development plans for the Greenhorn lime stone.
- Bonanza Creek and PDC are following Noble's lead in high density well count, extending the vertical opportunity, and improving well results.

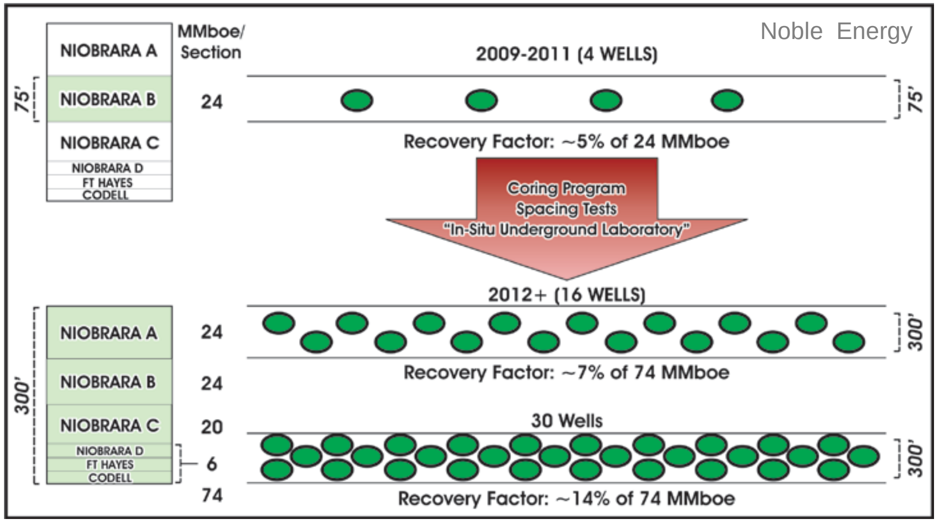
DJ Basin / Niabrara



DJ Basin / Niabrara: Noble Energy



DJ Basin Wattenberg: From 4 to 30 wells per DSU

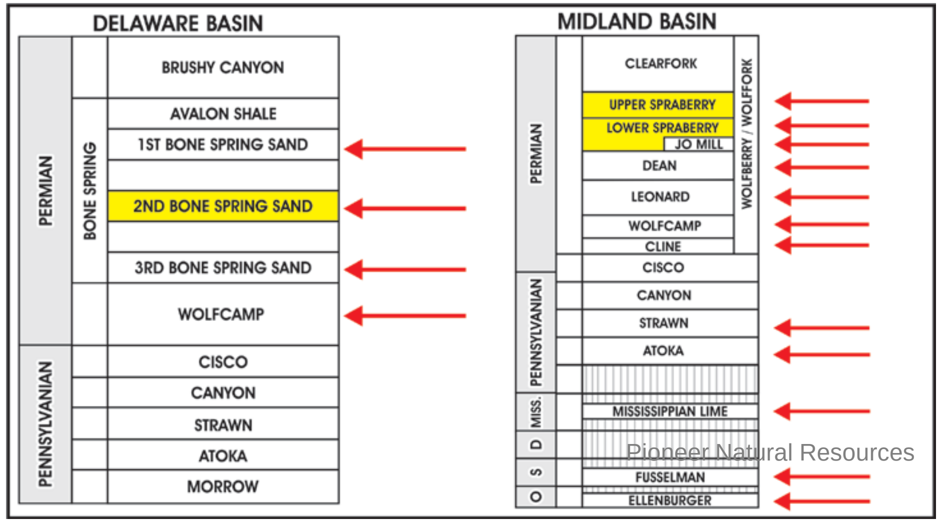


Wolfcamp: More Intervals, Tighter Spacing & Improved Rates/EURs

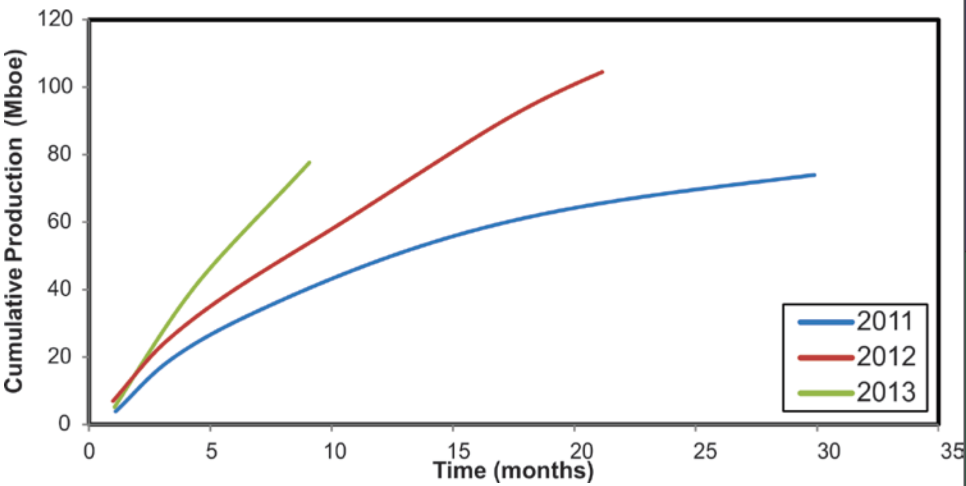
Pioneer Resources Leading Development

- 24 hr IP of 3,176 BOEP (83% OIL), 9,542’ lateral length. Well performance approaching EF status
- Down spacing pilots to 50 acre equivalent
- Wolfcamp D: recent well University 7-43 10H in Andrews county extended the play 60 miles to the west (24-hr IP: 3,605 BOEPD 7,382’ lateral length).
- Approach has extended the B and C benches south in to Crocket county, Highmount even further south in to Sutton county.

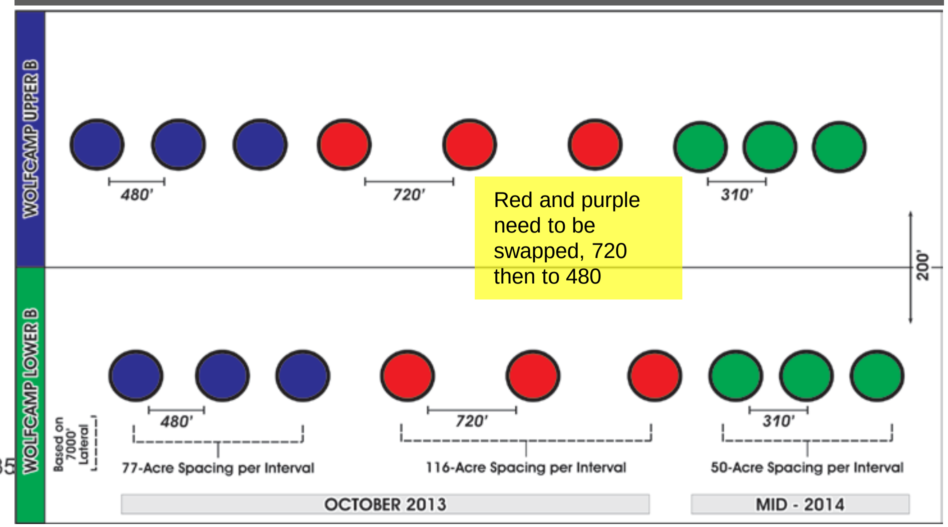
Permian / Wolfcamp



Permian / Wolfcamp: Approach Resources



Permian Wolfcamp: From 14 to 35 wells per DSU



Hypothetical & Actual Models Were Built to Demonstrate Profitability

Hypothetical Models Were Constructed to Study the Cost of Entry for the Following:

- Eagle Ford
- DJ Wattenberg
- Bakken

The hypothetical models were built using core area type curves and top quartile operating performance (capex, opex, etc.). Spacing, drill times, well count, and acreage were set to such that a equivalent comparisons could be made. The concept is to compare the years needed to attain free cash flow if 30% of the PV10 were used as an acquisition cost.

Three Transactions and One Start Up were Modeled

- Eagle Ford – Marathon Oil Company
- Bakken – Statoil
- Permian Wolfcamp – Approach Resources
- DJ Wattenberg – Bonanza Creek Energy Inc.

The transactions were modeled such that cost of purchase and associated future development was forecast to determine the timing of free cash flow and other key economic and production metrics. Data was obtained from public sources including investor relations slides.

Material New Entries Can Attain Free Cash Flow in Six Years

Assuming an entry fee of totaling 30% of the PV10, Free cash flow can be attained in six to eight years with an eight rig program

Years to Reach Free Cash Flow

Bakken — Entry Fee (as a % of PV-10)

	15%	20%	30%	50%	70%	80%	100%	120%
	$1.33 B	$1.77 B	$2.65 B	$4.42 B	$6.18 B	$7.07 B	$8.83 B	$10.6 B
2 Rigs	12	15	24	NA	NA	NA	NA	NA
4 Rigs	8	9	12	19	NA	NA	NA	NA
6 Rigs	7	8	9	13	17	23	NA	NA
8 Rigs	6	7	8	11	13	16	NA	NA
10 Rigs	6	6	7	9	11	13	20	NA
12 Rigs	6	6	7	8	10	11	17	NA
14 Rigs	5	6	6	7	9	10	15	NA
16 Rigs	5	5	6	7	9	10	13	25

Eagle Ford — Entry Fee (as a % of PV-10)

	15%	20%	30%	50%	70%	80%	100%	120%
	$2,033,731	$2,711,642	$4,067,463	$6,779,104	$9,490,746	$10,846,567	$13,558,209	$16,269,851
2 Rigs	9	12	21	NA	NA	NA	NA	NA
4 Rigs	6	7	9	16	NA	NA	NA	NA
6 Rigs	4	5	7	10	15	20	NA	NA
8 Rigs	4	4	6	8	11	13	NA	NA
10 Rigs	3	4	5	7	9	10	18	NA
12 Rigs	3	4	4	6	7	9	13	NA
14 Rigs	3	3	4	5	7	8	11	NA
16 Rigs	3	3	4	5	6	7	10	24

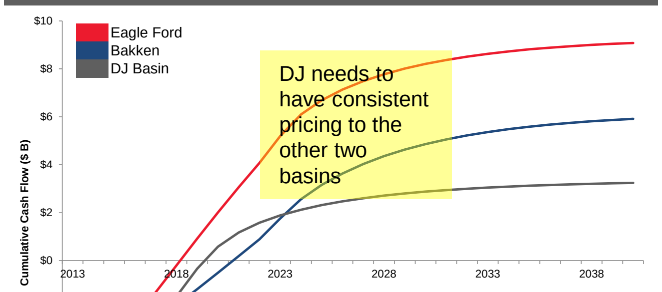
DJ Basin — Entry Fee (as a % of PV-10)

	5%	10%	15%	20%	25%	30%	40%	50%
	$215,989	$431,978	$647,968	$863,957	$1,079,946	$1,295,935	$1,727,914	$2,159,892
2 Rigs	8	8	9	9	10	11	12	14
4 Rigs	7	7	8	8	9	10	10	11
6 Rigs	7	7	7	7	8	8	8	9
8 Rigs	6	6	6	6	7	7	7	8
10 Rigs	5	5	6	6	6	6	7	7
12 Rigs	5	5	5	5	6	6	6	7
14 Rigs	5	5	5	5	5	5	6	7
16 Rigs	4	5	5	5	5	5	6	7

Model Inputs: 1000 Wells

- Entry fee as a percentage of PV10
- 1000 well locations
- One well drilled per month
- Costs and type curves from best operators
- Opex from best operators
- Basin spacing practices

Eagle Ford, Bakken, & DJ Models



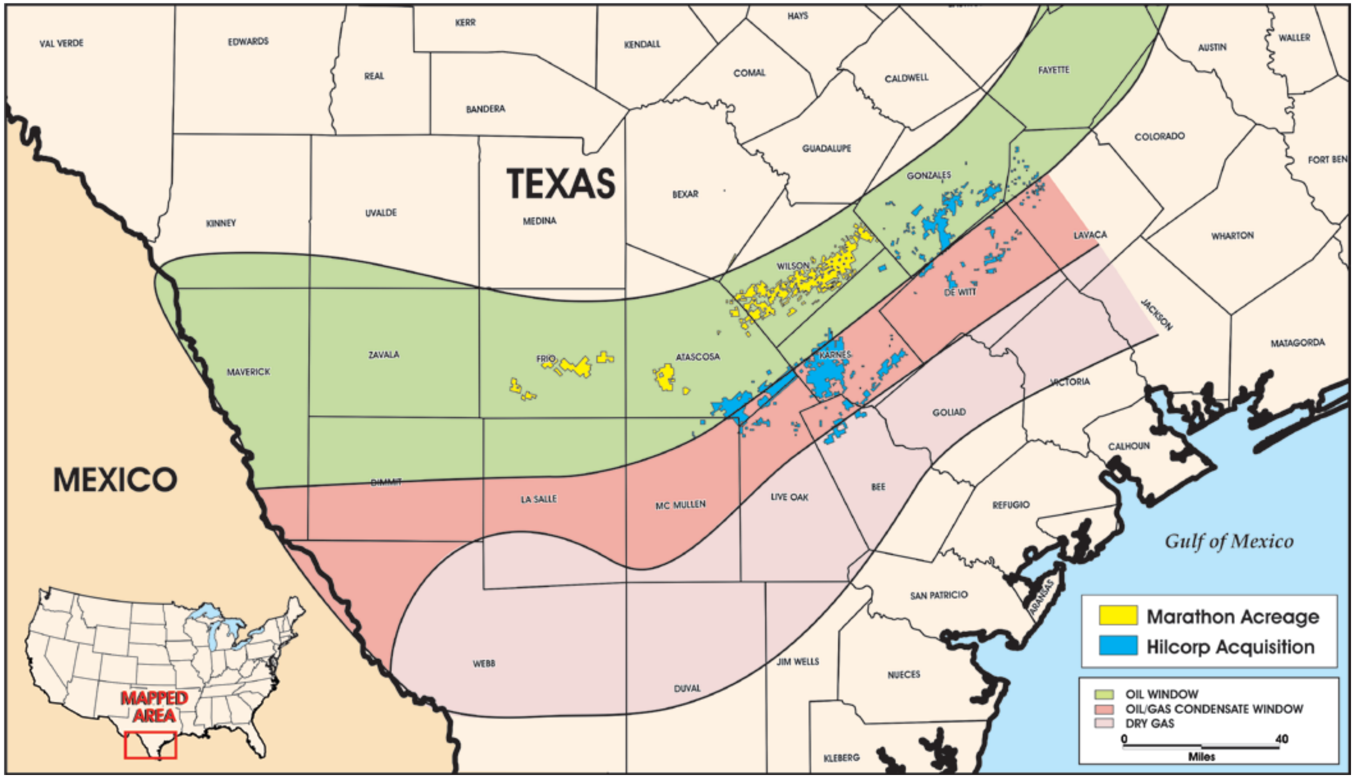
	Eagle Ford	Bakken	DJ Basin
Realized Price	$103	$87	$97
Acreage	40,000	320,000	80,000
Spacing	40	320	80
Well drill rate	1 / month	1 / month	2 / month
PV 10	$13.5 B	$8.8 B	$3.4 B
Entry Fee (30% PV 10)	$4.0 B	$2.7 B	$1.3 B
Break Even (years)	6	8	7

Marathon Acquires Hilcorp Resources Holding in the Eagle Ford Shale

Deal was accretive to Marathon's existing position in the Eagle Ford Shale.

Marathon paid $3.5 billion or approximately $25,000 per acre, to enter the play at essentially the peak of acreage acquisition when 'sweet spots' had clearly been defined.

- Transaction Close Date: 2011-11-01
    - Effective date of May 1, 2011
- 141,000 net acres for $3.5B
- 90% Operated
- 65% Avg WI
- 37 producing wells, 7,000 net boe/d
- Effective date of May 1, 2011



Development Plan Assumptions

The development plan assumed three distinct areas: Condensate, Volatile Oil, and Black Oil.

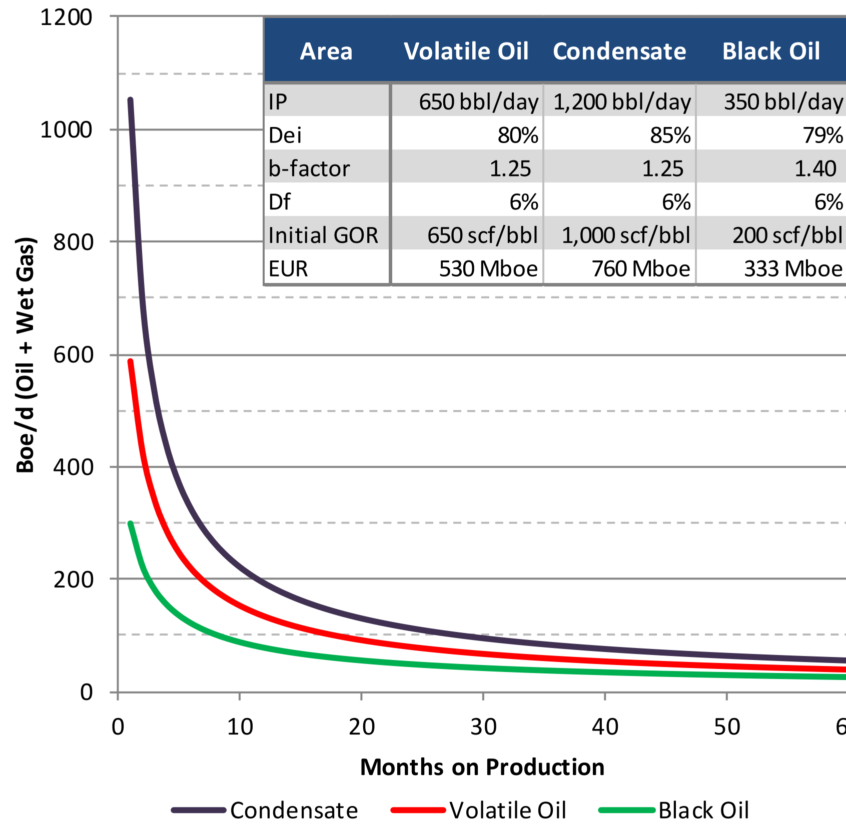
Marathon's existing acreage is not included in the development model and DCF, but consideration is given to their existing rig counts and operations in the area.

Development Plan Assumptions

Area	Volatile Oil	Condensate	Black Oil
Gross Ac (000)	102	56	26
Net Ac (000)	51	41	23
Avg WI	50%	73%	88%
Royalty	25%	25%	25%
NRI	38%	55%	66%
Rigs	4	6	2
Aggressive Spacing (ac)	40	40	80
Conservative Spacing (ac)	80	80	160
Acreage Attrition	10%	10%	10%
Gross Wells (aggressive)*	2295	1260	293
Gross Wells (conservative)	1148	630	147
Well Cost ($MM)	7.9	7.9	7.9
Fixed Opex ($/well/mo)	850	850	850
Var Opex Oil ($/bbl)	8.2	8.2	8.2
Var Opex Gas ($/mcf)	0.77	0.77	0.77
Oil Price Deduct ($/bbl)	$ (1.50)	$ (1.50)	$ (1.50)
Gas Price Deduct ($/mcf)	$ (0.25)	$ (0.25)	$ (0.25)
Drilling Cycle Time (S-S d)	25	25	25

*At the time of the acquisition the Eagle Ford was not being drilled as densely as it is now, and the conservative well space was likely assumed. Current down spacing assumption are included in the aggressive well count

Type Curve Parameters

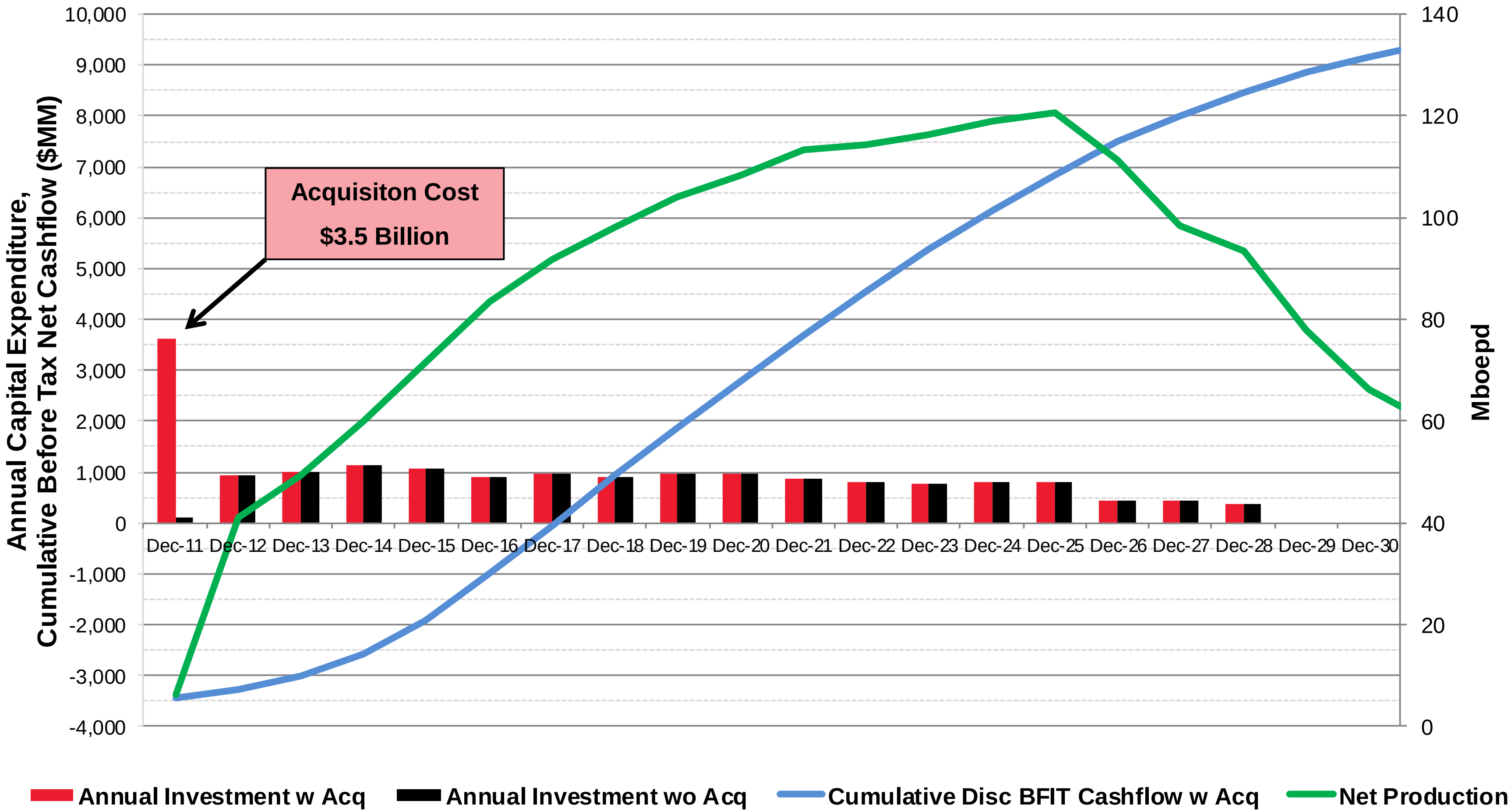


Area	Volatile Oil	Condensate	Black Oil
IP	650 bbl/day	1,200 bbl/day	350 bbl/day
Dei	80%	85%	79%
b-factor	1.25	1.25	1.40
Df	6%	6%	6%
Initial GOR	650 scf/bbl	1,000 scf/bbl	200 scf/bbl
EUR	530 Mboe	760 Mboe	333 Mboe

Economics of Transaction and Associated Future Development

Life cycle results without acquisition costs	
• BTAX IRR:	100%
• BFIT PV10:	14.6 B
• Project Payout:	2012

Life cycle results with acquisition costs	
• BTAX IRR:	29.5%
• BFIT PV10:	11.6 B
• Project Payout:	2017



Historical annual pricing for 2011 - 2013, $100/bbl oil, $30/bbl ngl and $4/mcf gas used going forward.

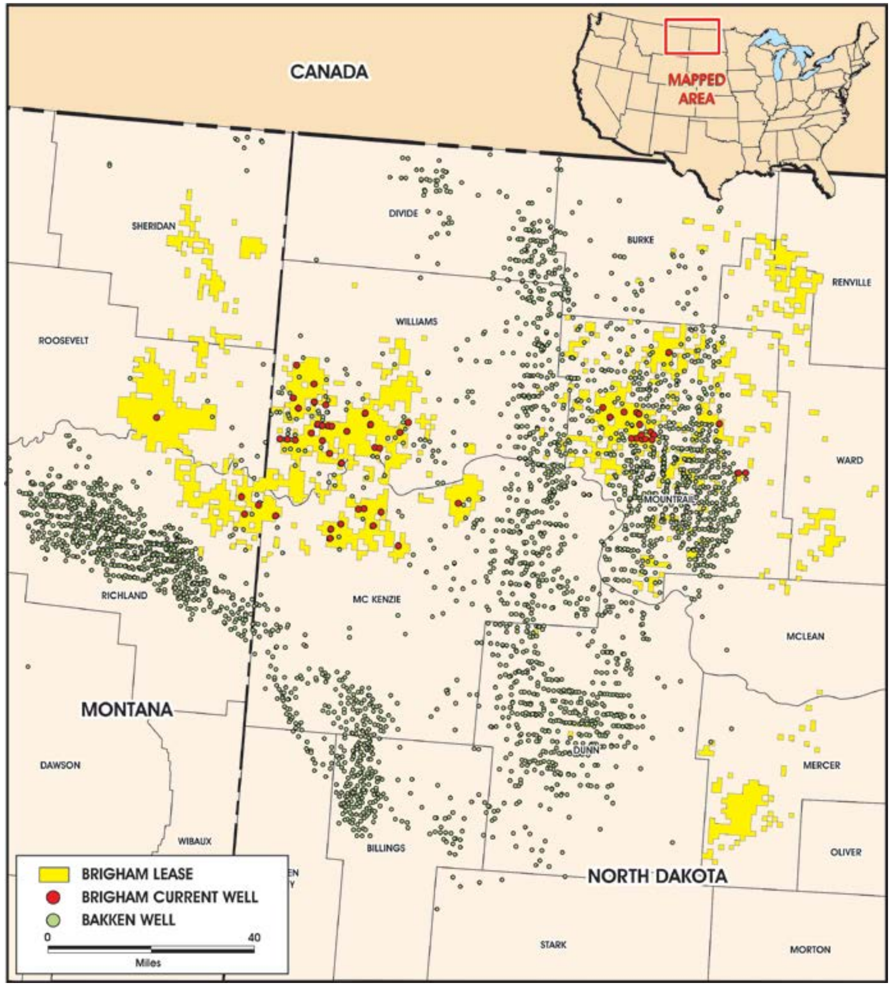
Statoil Acquires Brigham Exploration – Enters Williston Basin

Statoil adds to existing Onshore US position through the acquisition of Brigham Exploration. The transaction immediately adds production growth and reserve additions and makes Statoil a leading operator in the Bakken.

Transaction Highlights

- All cash offer of 4.7 Billion
    - Estimated Price paid for the Bakken^ – 4.47 Billion
    - Close Date: Dec 8, 2011
    - Effective date of Dec 1, 2011*
- At the time of the transaction Brigham had approximately 17,000 boe/d of net production and net proved reserves of 67 MMboe
- Acreage Position^
    - 40,000 net acres in Texas & Oklahoma^
    - 600,000 gross / 375,000 net acres in the Bakken
        - 60% de-risked
        - 300-500 MMboe risked resource base
    - Gross unrisked recoverable resource 1,980 MMboe
- Brigham was among the top 15 lease holders in the basin and top 10 most active drillers in the basin at the time of the transaction

Brigham Exploration - Williston Basin

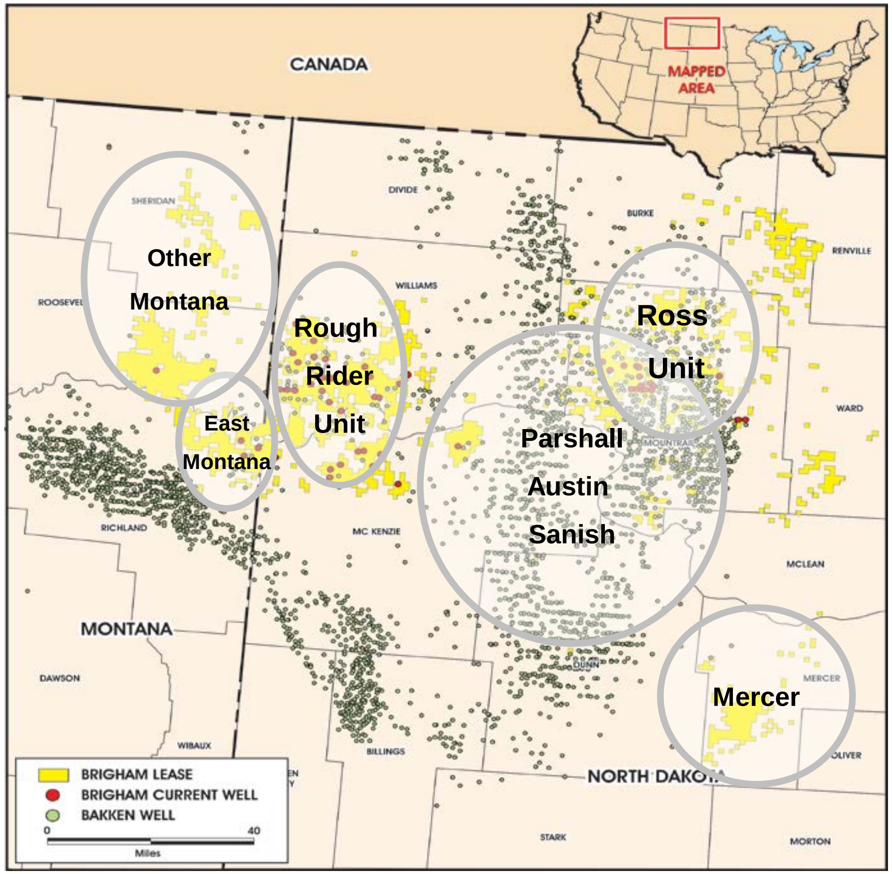


*Effective date used for DCF model on subsequent pages.
^40,000 net acres outside of the Williston Basin was not included in this analysis

Pace of Development: Rig Count Drives Wells Drilled and Economics

- Statoil is developing in six core operating areas
- Statoil's average NWI across the play is 60% and they operate 90% of their total acreage
- The operated rig count dropped from 15 – 10 in 2013, but is expected to ramp back up by 2017

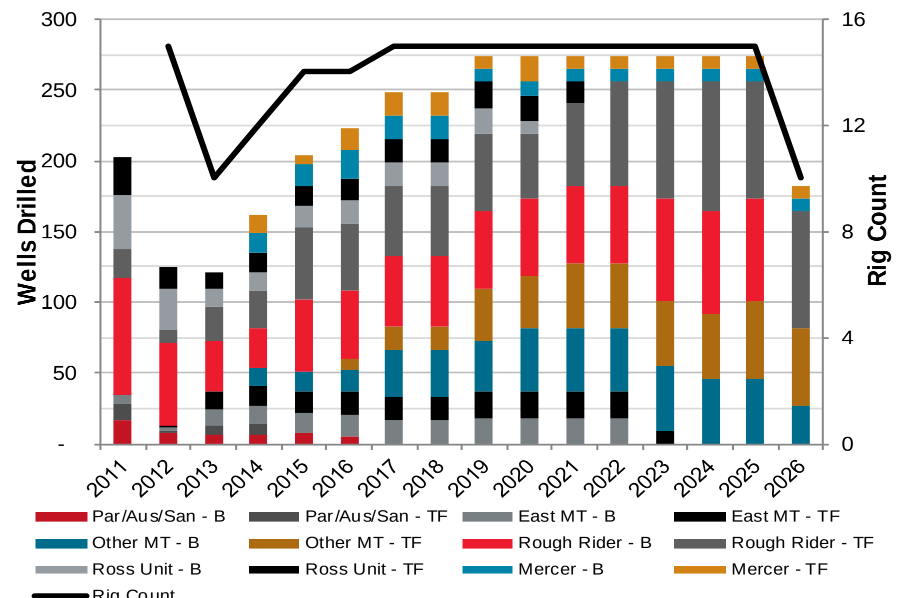
Core Areas



Prospective Acreage

Area	Reservoir	Prospective Net Acres	Gross Acres	Total Net Wells	Gross Net Wells
Par/Aus/San	Bakken	4,900	8,167	30	50
	Three Forks	2,450	4,083	15	25
East MT	Bakken	33,500	55,833	104	173
	Three Forks	33,500	55,833	104	173
Other MT	Bakken	85,600	142,667	267	445
	Three Forks	85,600	142,667	267	445
Rough Rider	Bakken	161,600	538,667	505	1,683
	Three Forks	161,600	538,667	505	1,683
Ross Unit	Bakken	35,200	58,667	110	183
	Three Forks	35,200	58,667	110	183
Mercer	Bakken	30,100	50,167	94	157
	Three Forks	30,100	50,167	94	157

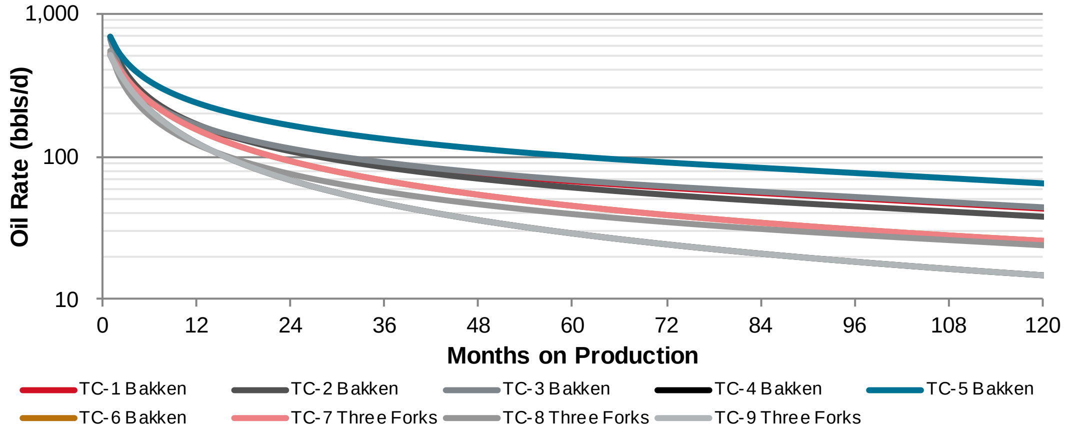
Pace of Development



Development Plan Assumptions: Optimistic Outside of Core Areas

- The Williston Basin is being developed almost exclusively with horizontal wells
- Statoil is developing the majority of there acreage on 1,280 acre units with 10,000 ft lateral wells
  - Currently 4 Bakken and 4 Three Forks wells are planned for each drilling unit
  - Well spacing is approximately 320 acres in each producing reservoir

Type Curve Parameters



Model Inputs

Economic Input Assumptions		
Operating Cost	$1,667	per well/mo
	$1.09	per MCF
	$6.55	per bbl
Pricing Differential	$9.98	per bbl
	$0.35	per MCF
Ad Val Tax	0.00%	
Ownership	60.00%	WI
	49.20%	NRI
	18.00%	Roy
Sev Tax	$0.1476	per MCF
	11.50%	Oil
Capex	$8.95	MM/well

Pricing	2012	2013	2014+
Oil ($/bbl)	94.05	95.70	100.00
Gas ($/Mcf)	2.75	3.73	4.00
NGL ($/bbl)	28.22	28.71	30.00

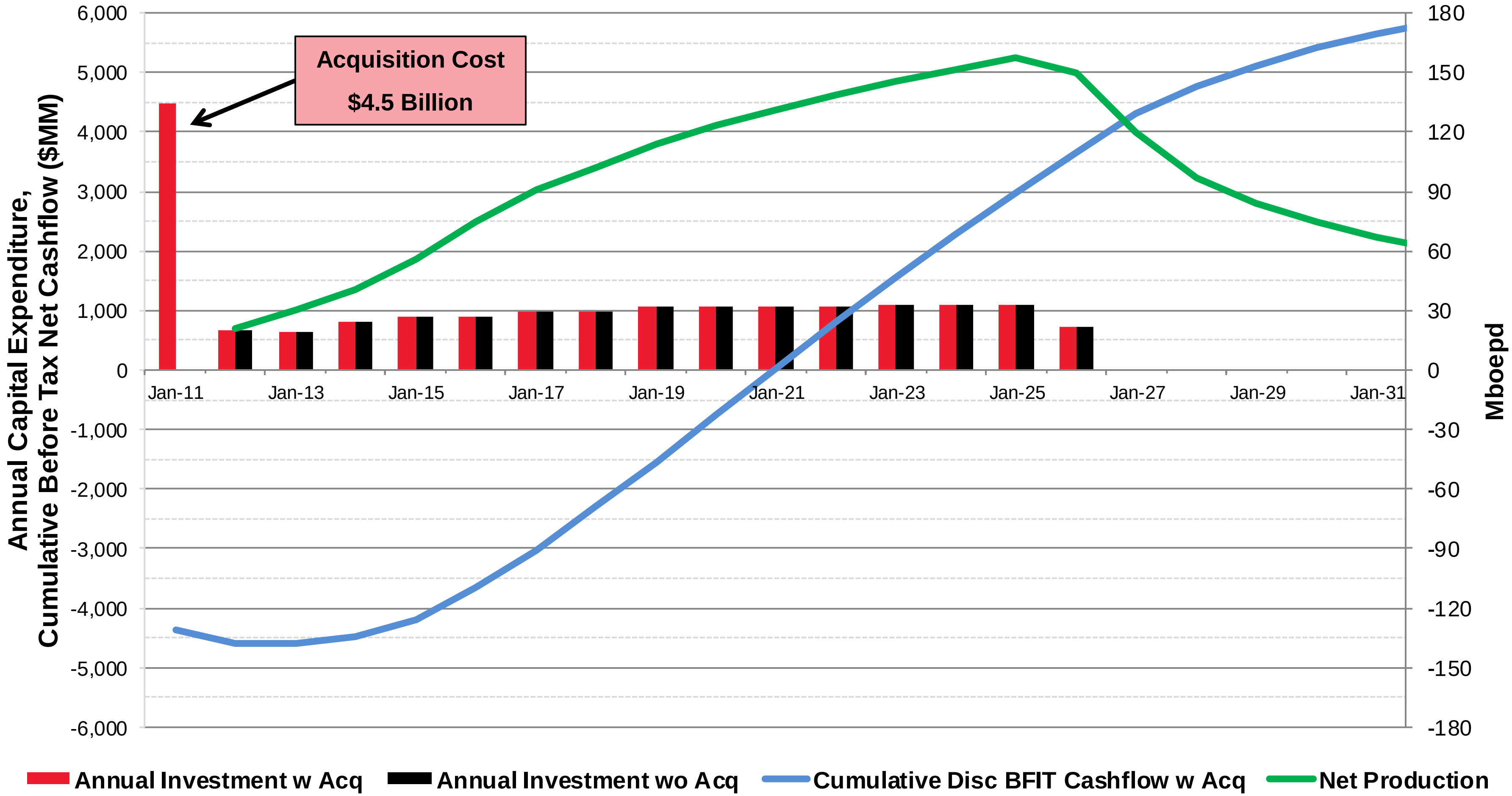
Type Curve Parameters

Operating Area	Reservoir	Type Curve	Oil IP (bbls/d)	B Factor	Initial Decline (%)	GOR (scf/bbl)	WOR (bbl/bbl)	EUR (Mboe)
Ross Unit	Bakken	TC-1	975	1.8	83.6	818	0.71	593
Rough Rider (Williams County)	Bakken	TC-2	875	1.55	81.3	860	0.969	558
Rough Rider (McKenzie County)	Bakken	TC-3	900	1.8	81.9	989	0.96	619
East MT, Other MT	Bakken	TC-4	590	1	79.6	697	1.53	294
Par/Aus/San	Bakken	TC-5	800	1.8	71.0	2340	0.6	1,054
Mercer	Bakken	TC-6	600	1.8	75.1	1024	1.28	441
Par/Aus/San, East MT, Other MT, Rough Rider (Williams County), Rough Rider (McKenzie County)	Three Forks	TC-7	600	1.8	75.1	1024	1.28	441
Ross Unit	Three Forks	TC-8	700	1.2	83.1	2518	1.281	469
Mercer	Three Forks	TC-9	590	1	79.6	697	1.53	294

Economics of Transaction and Associated Future Development

Life cycle results without acquisition costs	
• BTAX IRR:	86.7%
• BFIT PV10:	11.2 B
• Project Payout:	2014

Life cycle results with acquisition costs	
• BTAX IRR:	19.4%
• BFIT PV10:	6.8 B
• Project Payout:	2020



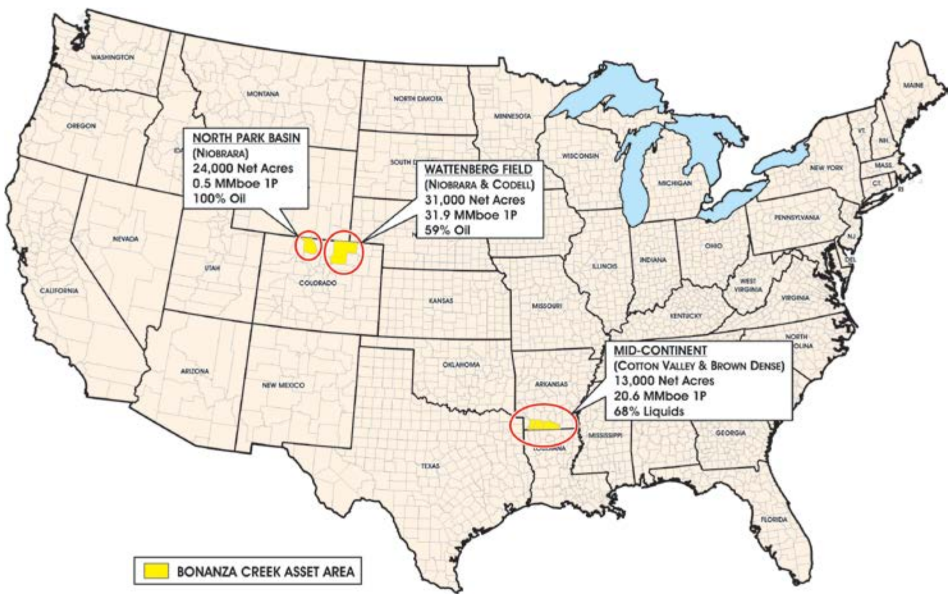
Historical annual pricing for 2011 - 2013, $100/bbl and $4/mcf gas used going forward.

Bonanza Creek Energy: Successful Fast Follower in the Wattenberg

Bonanza Creek Energy Inc. with a group lead by West Face Capital Inc. formed a new E&P company, monetizing the predecessor (Bonanza Creek Energy Company, LLC) and additionally acquiring Mid-Continent and Rocky Mountain Assets from Holmes Eastern Company.

Transaction Highlights

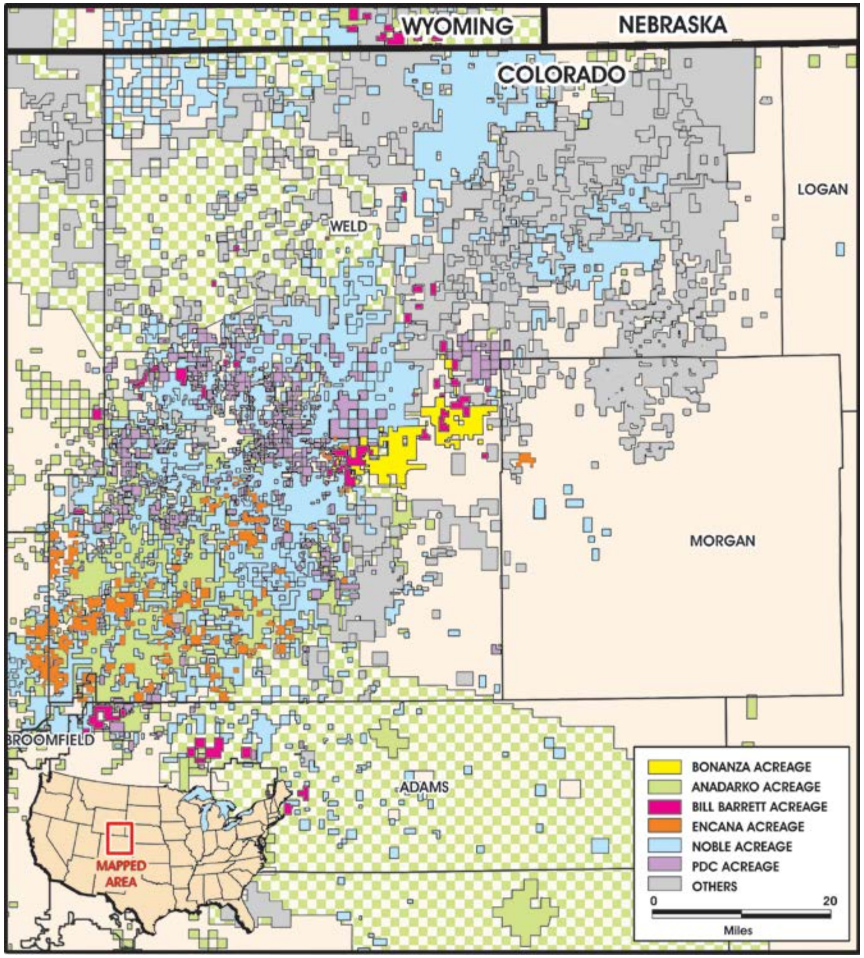
- Close Date: Dec 23, 2010
  - Effective date of Dec 1, 2010*
- At the time of the transaction BCEI had approximately 4,100 boe/d of production and proved reserves 30MMboe



*Effective date used for DCF model on subsequent pages.
^6,000 acres in the San Joaquin Basin of California was also acquired and subsequently divested and is not included in this analysis.

Wattenberg Field

- This area represents the core of BCEI's acreage and the focus of development since 2012
- BCEI's acreage position is in what is considered the extension area of the Wattenberg field, adjacent to the core operations of Noble, PDC and Anadarko.



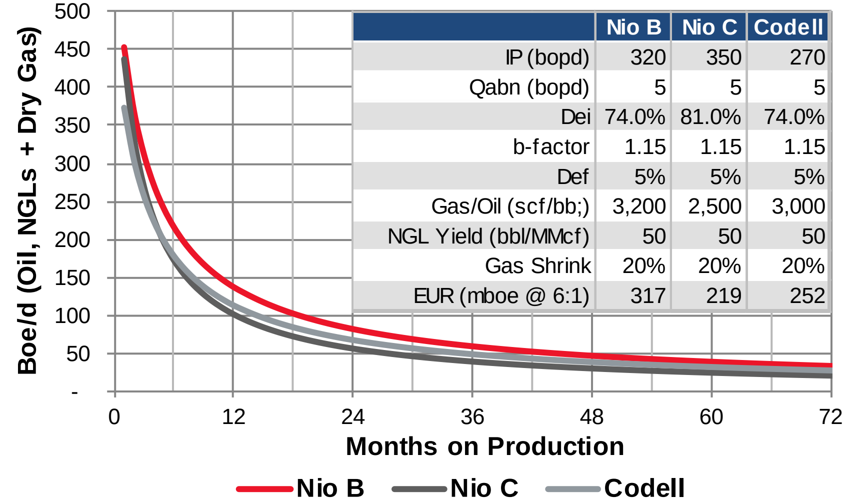
Following Front Runner Noble, BCEI is Improving in All Key Metrics

BCEI has shifted it's drilling focus to almost exclusively Wattenberg Hz Oil Development

Development Plan Assumptions

- BCEI has drilled a combination of vertical and horizontal wells into the Niobrara and Codell formations, beginning in 2011 the HZ activity began to ramp up
- 2013 and forward development is assumed to be exclusively horizontal drilling.
- The primary zones of interest are the Niobrara B, C and the Codell
  - BCEI is currently evaluating additional benches for prospectively
- This field is currently being developed with 4,000' laterals on 80 ac spacing in Nio B and C benches and at 160 ac spacing in the Codell
  - 40 ac downspacing and extended reach laterals (9,000') are currently being evaluated by BCEI (Noble is doing this routinely) at this time are still in the early stages of being evaluated.
  - Offset operators such as Noble are currently downspacing to a minimum of 16 wells at 40 acres and evaluating higher densities of over 30 wells per section including additional Niobrara benches.
  - Noble is routinely drilling 9,000' laterals.

Type Curve Parameters



	Nio B	Nio C	Codell
IP (bopd)	320	350	270
Qabn (bopd)	5	5	5
Dei	74.0%	81.0%	74.0%
b-factor	1.15	1.15	1.15
Def	5%	5%	5%
Gas/Oil (scf/bb;)	3,200	2,500	3,000
NGL Yield (bbl/MMcf)	50	50	50
Gas Shrink	20%	20%	20%
EUR (mboe @ 6:1)	317	219	252

Model Inputs

Economic Input Assumptions

Operating Cost	$250	per w ell/mo	Ownership	93.00%	WI
	$1.05	per MCF		76.26%	NRI
	$6.55	per bbl		18.00%	Roy
Pricing Basis	$5.75	per bbl	Sev Tax	5.00%	Gas/NGL
	$0.37	per MCF		5.00%	Oil
Ad Val Tax	7.60%		Capex	$4.65	MM / w ell

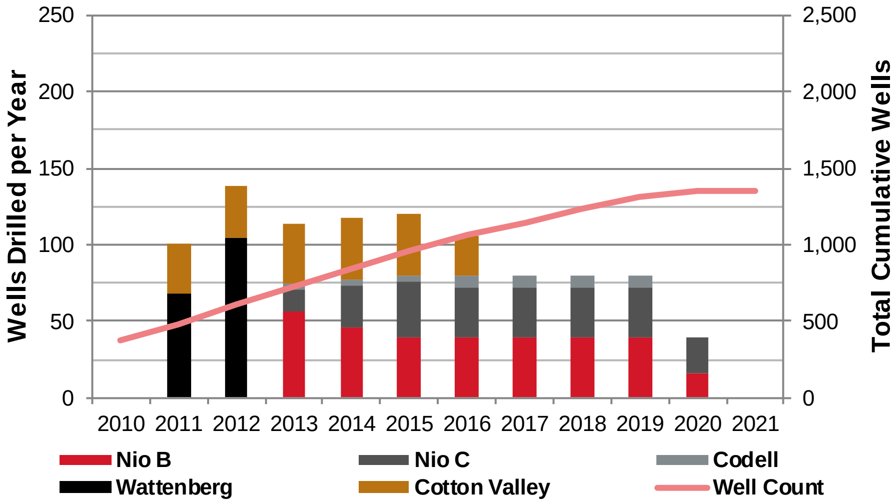
Pricing	2011	2012	2013	2014+
Oil ($/bbl)	94.88	94.05	95.70	100.00
Gas ($/Mcf)	4.00	2.75	3.73	4.00
NGL ($/bbl)	28.46	28.22	28.71	30.00

Development Plan: Future Plans will Improve Production & Economics

- The BCEI valuation was conducted using two endpoints to capture a reasonable range of values
- In both cases no additional development was assumed in the North Park basin
- In the Mid Continent it was assumed that the remaining acreage was drilled up to 10 ac spacing.*

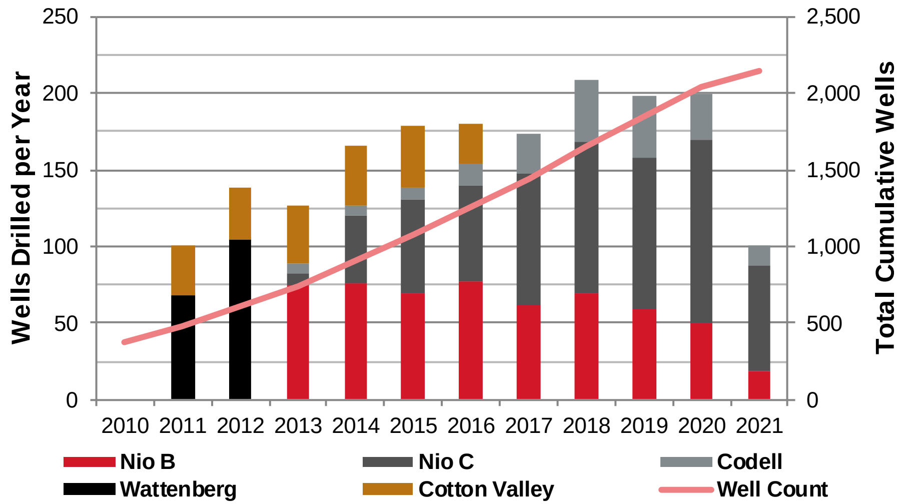
- Additional upside beyond these scenarios is present in the following:
  - Additional Wattenberg benches: Niobrara A, Wattenberg Greenhorn & extended reach laterals
  - Cotton Valley 5 ac spacing
  - Arkansas Brown Dense
  - North Park Basin Niobrara

Initial Drilling Plan



- Assumptions – 2013 forward drilling plan:
  - Nio B – 80 ac spacing – 318 wells
  - Nio C – 80 ac spacing – 229 wells
  - Codell – 160 ac spacing – 44 wells
  - Cotton Valley – 10 ac spacing – 144 wells

Future/Upside Drilling Plan



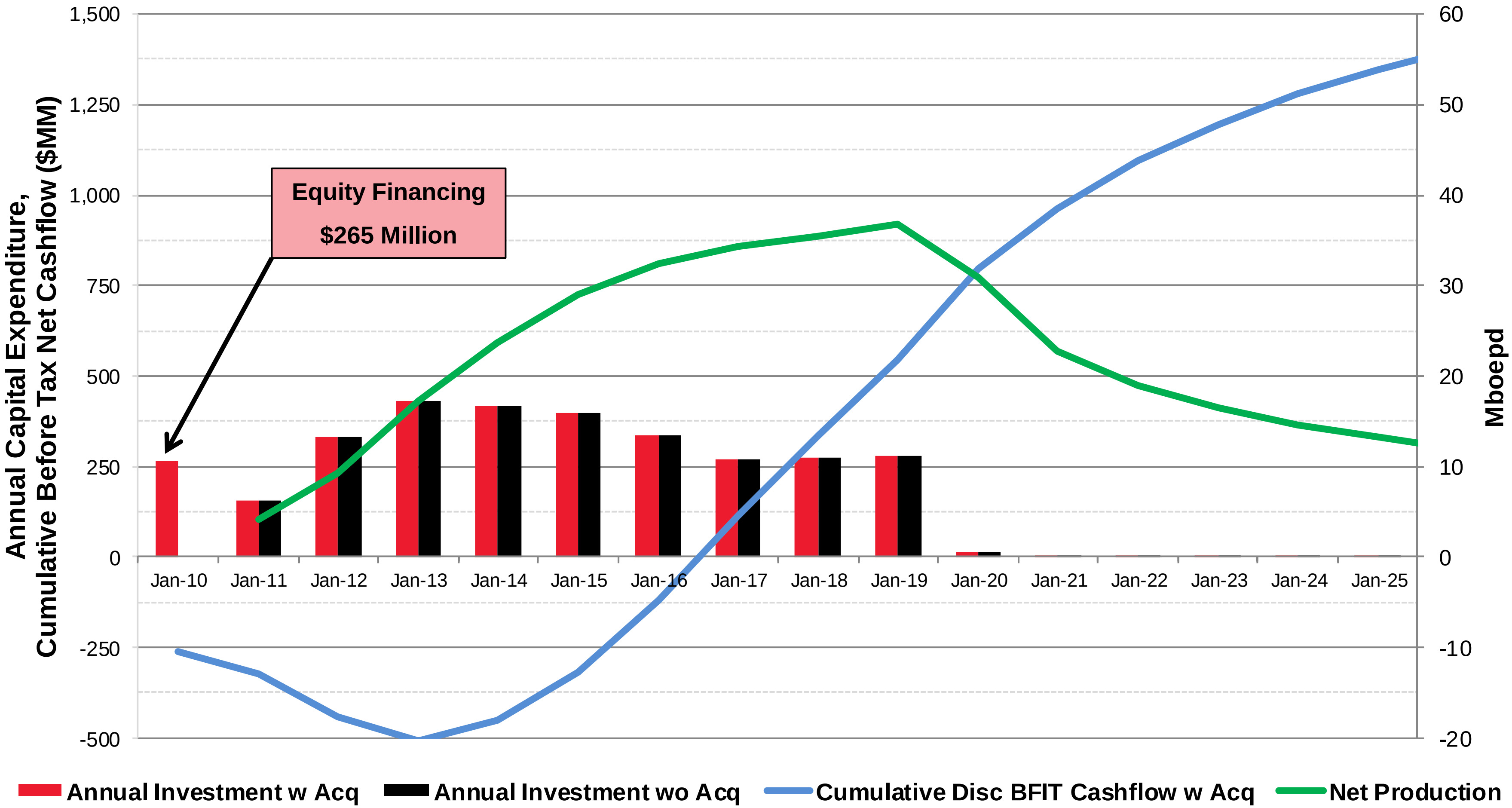
- Assumptions – 2013 forward drilling plan:
  - Nio B – 40 ac spacing – 554 wells
  - Nio C – 40 ac spacing – 650 wells
  - Codell – 80 ac spacing – 182 wells
  - Cotton Valley – 10 ac spacing – 144 wells

*Mid Continent development taken from Wood Mackenzie

Initial Drilling Plan Results from Company Formation Forwards

Life cycle results without acquisition costs	
• BTAX IRR:	56.5%
• BFIT PV10:	1.98 B
• Project Payout:	2015

Life cycle results with acquisition costs	
• BTAX IRR:	32.2%
• BFIT PV10:	1.71 B
• Project Payout:	2016

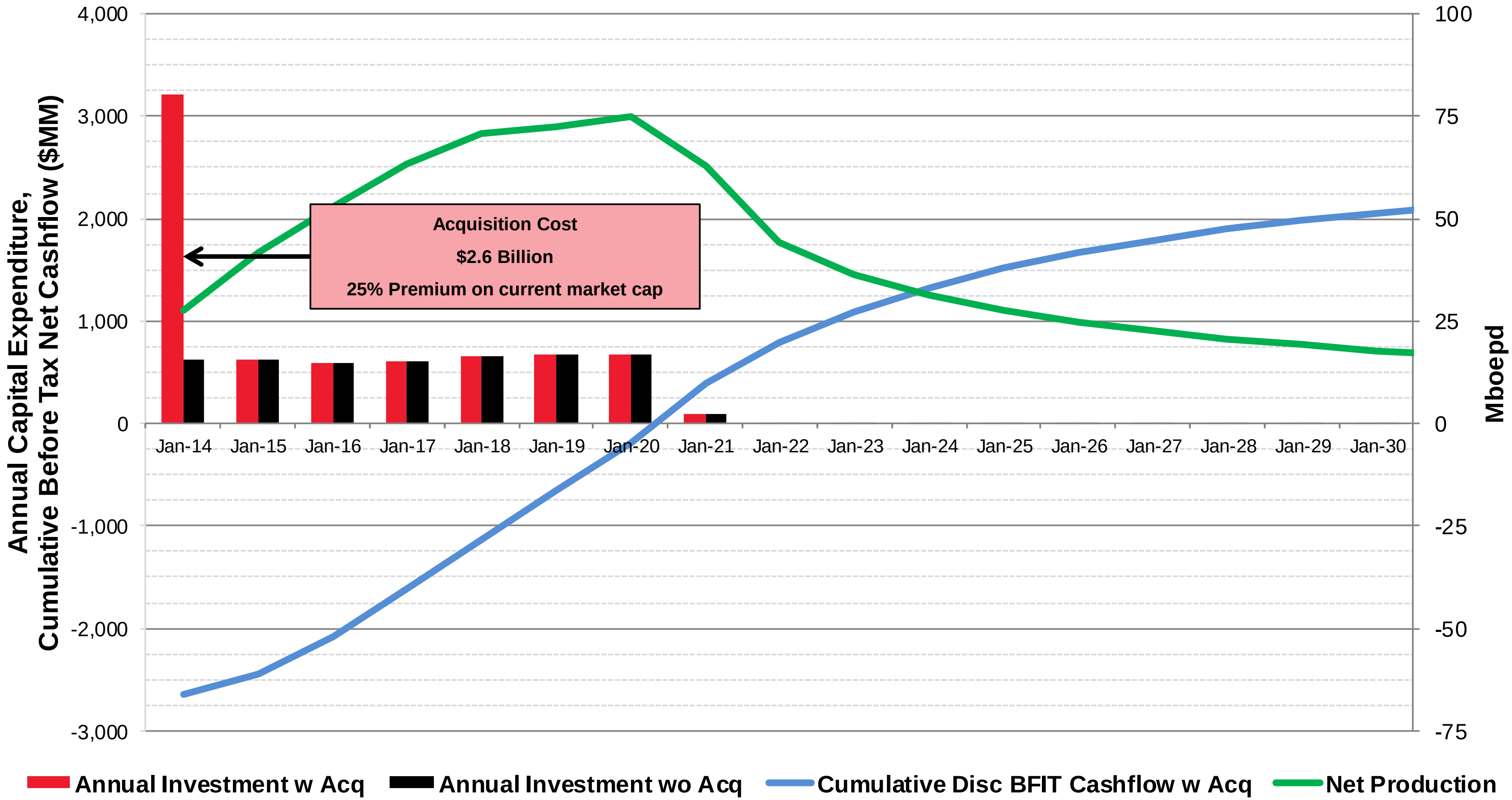


Historical annual pricing for 2011 - 2013, $100/bbl and $4/mcf gas used going forward.

Future Drilling Plans with Assumed Purchase Model

Life cycle results without acquisition costs	
• BTAX IRR:	100%
• BFIT PV10:	5.09 B
• Project Payout:	2015

Life cycle results with acquisition costs	
• BTAX IRR:	20.5%
• BFIT PV10:	2.49 B
• Project Payout:	2020



Historical annual pricing for 2011 - 2013, $100/bbl and $4/mcf gas used going forward.

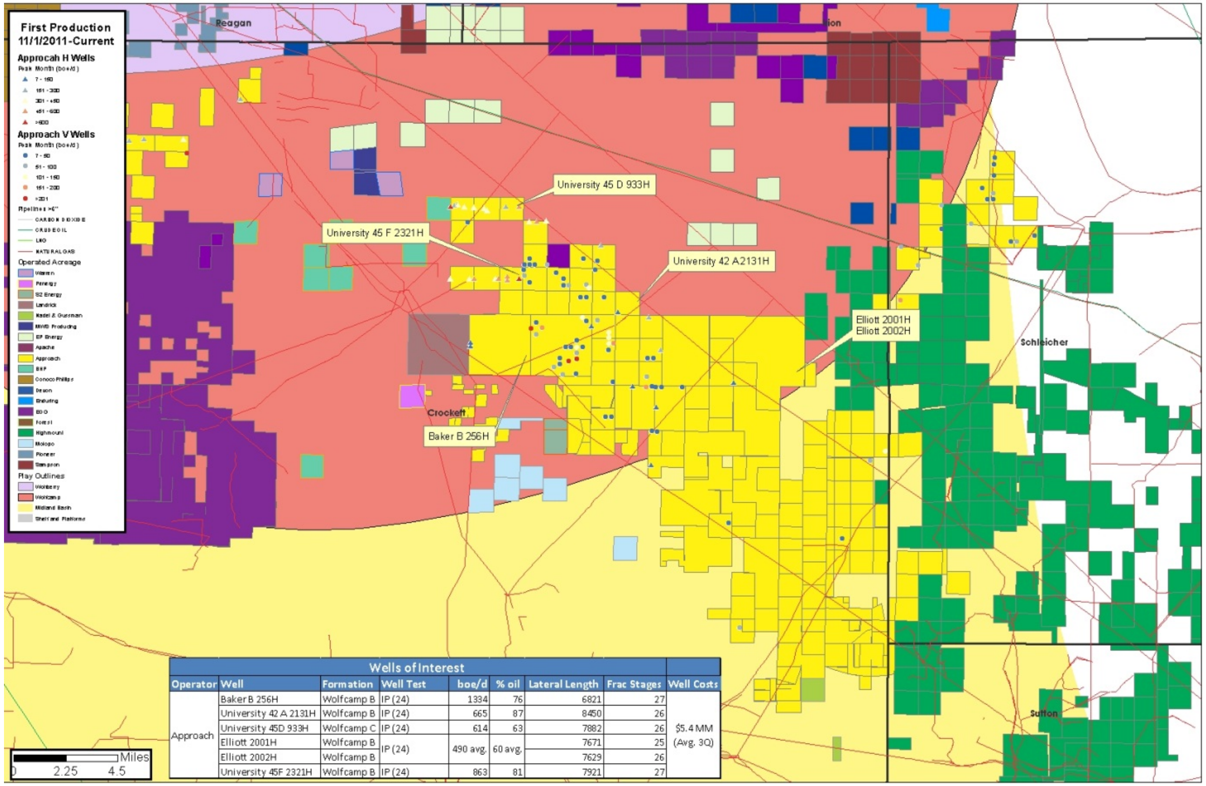
Approach Resources: A Pure Midland Basin Wolfcamp Play

Since 2009, Approach has increased its Wolfcamp reserves seven times by successfully completing a Wolfcamp pilot program and then extrapolating it to a larger-scale development.

Asset Overview

- 152,000 total net acres in the basin
- Q3 2013 net production of 8.8 Mboe/d
- 95.5 MMboe proved reserves at year-end 2012 (69% liquids)
- 2013 capital budget of $260 MM, of which 90% is allocated to Hz Wolfcamp
  - o Plan to drill ~40-42 Hz wells with 3 rigs
  - o Testing “stacked-wellbore” development and optimizing well spacing and completion design
- 2,000+ locations in Wolfcamp A, B & C
  - o Well costs average $5.5 MM for lateral length of ~7,000’
  - o Average EUR (gross) of 450 Mboe
  - o ~80% of EUR made up of oil and NGLs
- Gross potential resource of 943 MMboe split evenly amongst the three Wolfcamp benches
- Additional upside potential in the Wolfcamp D

Permian Asset Map



Wells of Interest

Operator	Well	Formation	Well Test	boe/d	% oil	Lateral Length	Frac Stages	Well Costs
Approach	Baker B 256H	Wolfcamp B	IP (24)	1334	76	6821	27	$5.4 MM (Avg. 3Q)
	University 42 A 2131H	Wolfcamp B	IP (24)	665	87	8450	26	
	University 45D 933H	Wolfcamp C	IP (24)	614	63	7882	26	
	Elliott 2001H	Wolfcamp B	IP (24)	490 avg.	60 avg.	7671	25	
	Elliott 2002H	Wolfcamp B				7629	26	
	University 45F 2321H	Wolfcamp B	IP (24)	863	81	7921	27	

Market Cap	EV	2014 EBITDA	EV / 2014EBITDA	2014 FC Flow	2014 Capex
$746 MM	$862 MM	$183 MM	4.7x (2014)	-$214 MM	$397 MM

Source: Approach Resources Investor Presentation August 2013

Development Plan Assumptions

Approach has been testing the upper three benches of the Wolfcamp on their acreage with very encouraging results.

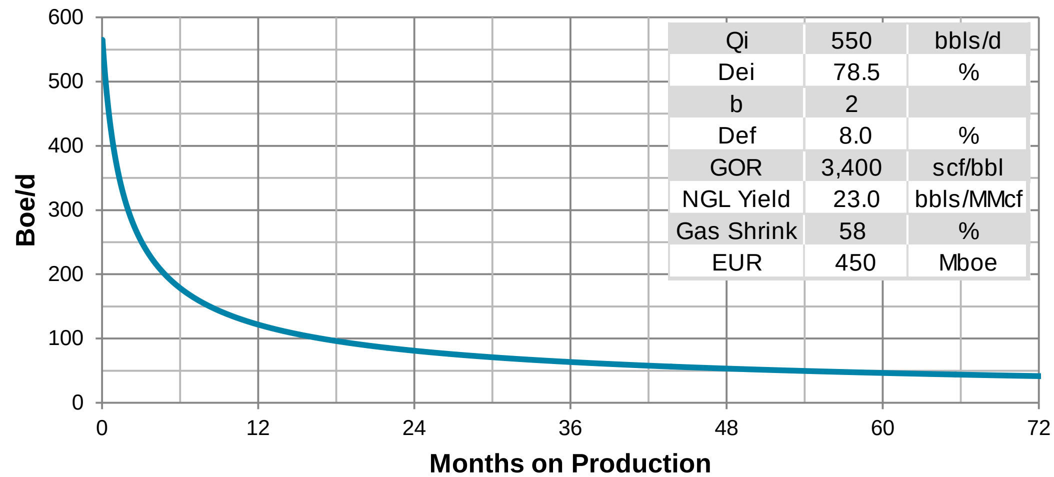
- ~2000 A,B & C locations are contemplated in this development
- Drill times are averaging 12 days for 2013 however pad drilling hasn't been implemented to date, it is included going forward.
- Current estimates are that the Wolfcamp D is prospective on about 50% of their acreage, 350 locations were included in the development plan.

Model Inputs

Economic Input Assumptions		
Operating Cost	$7.00	per bbl
Pricing Differential	$4.00	per bbl
	$0.35	per MCF
Ad Val Tax	4.00%	
Ownership	98.00%	WI
	73.50%	NRI
	25.00%	Roy
Sev Tax	7.50%	Gas
	4.60%	Oil
Capex	$5.50	MM/well

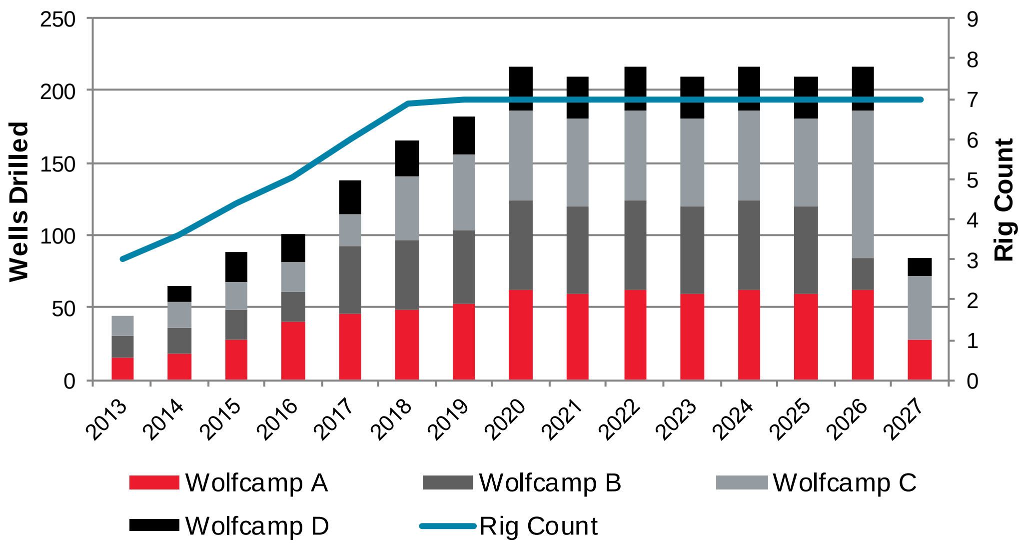
Pricing	2012	2013	2014+
Oil ($/bbl)	94.05	95.70	100.00
Gas ($/Mcf)	2.75	3.73	4.00
NGL ($/bbl)	28.22	28.71	30.00

Type Curve Parameters



Qi	550	bbls/d
Dei	78.5	%
b	2	
Def	8.0	%
GOR	3,400	scf/bbl
NGL Yield	23.0	bbls/MMcf
Gas Shrink	58	%
EUR	450	Mboe

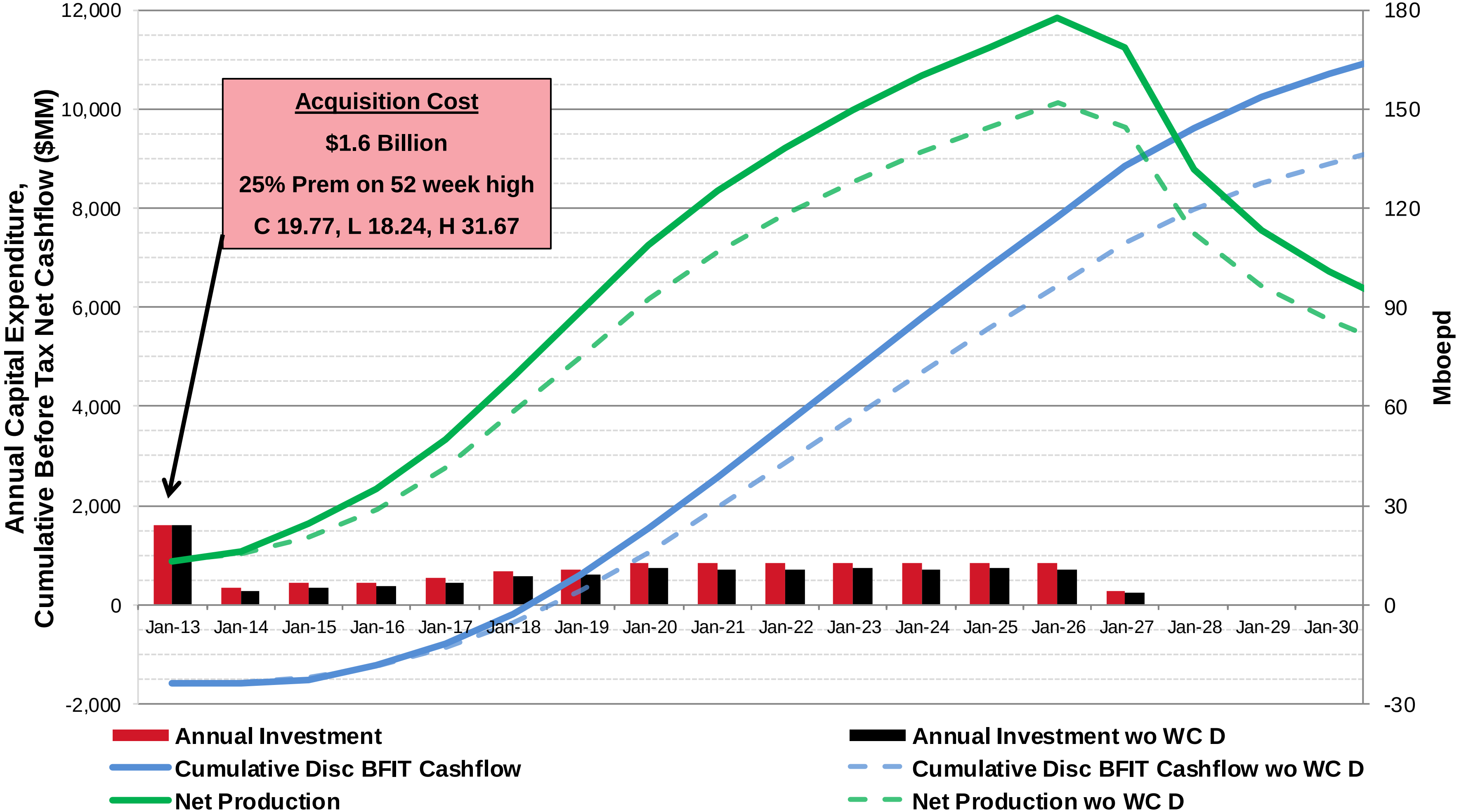
Pace of Development



Results of Assumed Development Plan

Life cycle results with upside Wolfcamp D	
• BTAX IRR:	41.2%
• BFIT PV10:	13.1 B
• Project Payout:	2018

Life cycle results without upside Wolfcamp D	
• BTAX IRR:	38.3%
• BFIT PV10:	11.0 B
• Project Payout:	2019



Historical annual pricing for 2011 - 2013, $100/bbl and $4/mcf gas used going forward.