Canaccord Genuity 2011 Global Energy Conference

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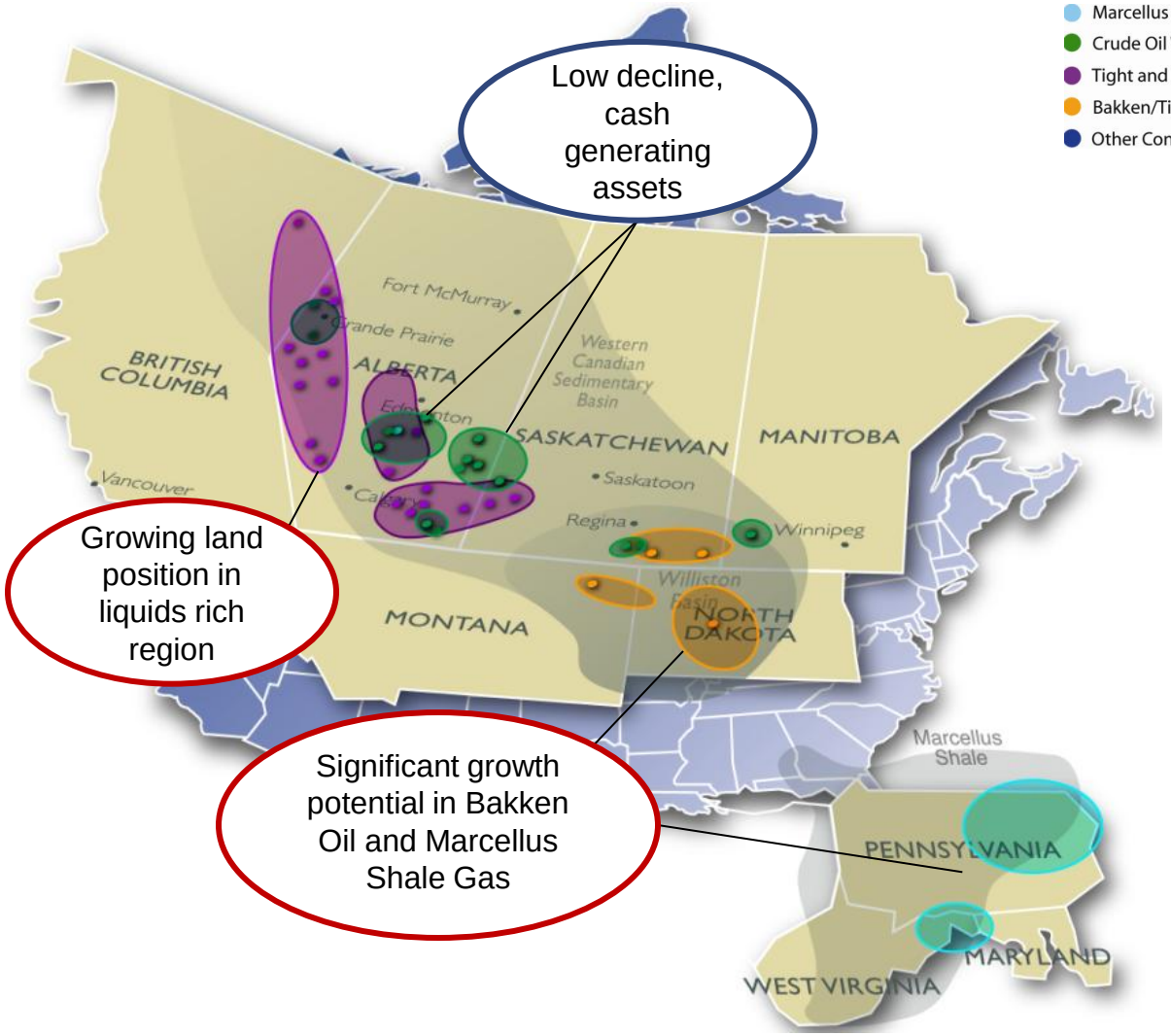
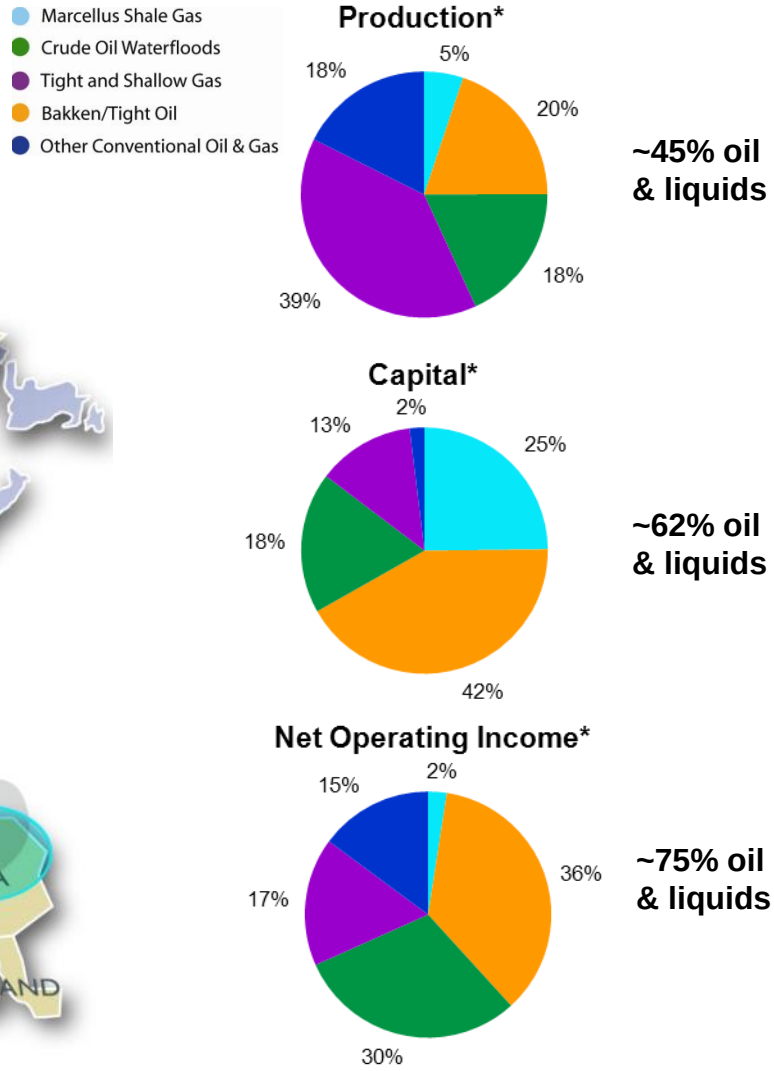
enerPLUS

Enerplus Overview

- North American oil and gas producer focused on providing growth and income
  - Current yield of over 8%
  - 10 – 15% production growth expected through 2012
- Diversified portfolio of oil and gas properties throughout Western Canada and the U.S.
  - Low decline properties primarily in Western Canada generating free cash flow
  - Bakken, waterfloods and Marcellus provide future growth in reserves and production
  - Undeveloped land positions in Montney, Stacked Mannville and Duvernay
- Strong balance sheet supports growth plans

Our Assets

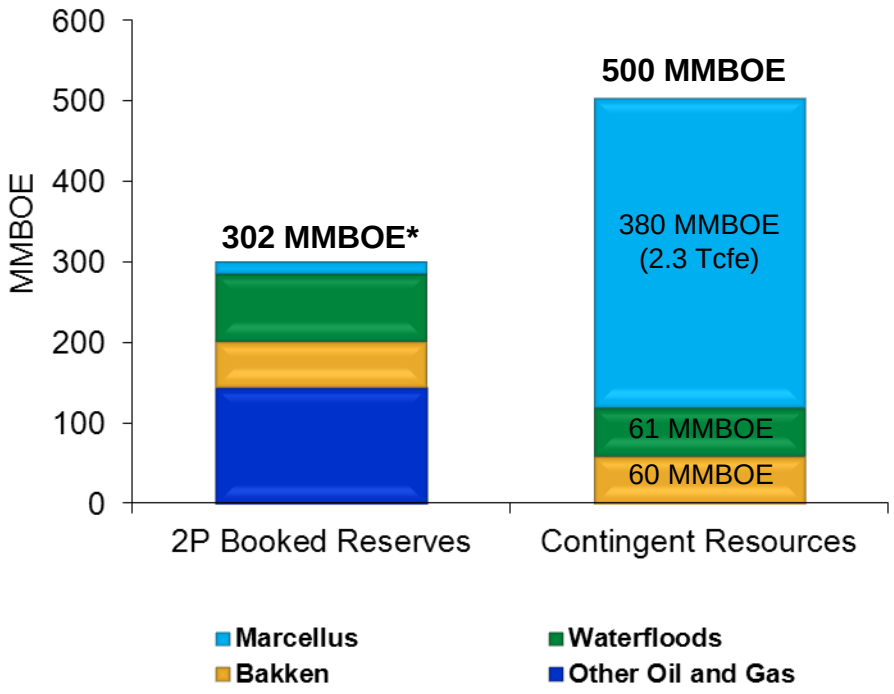




* 2011 estimates

Growth Potential

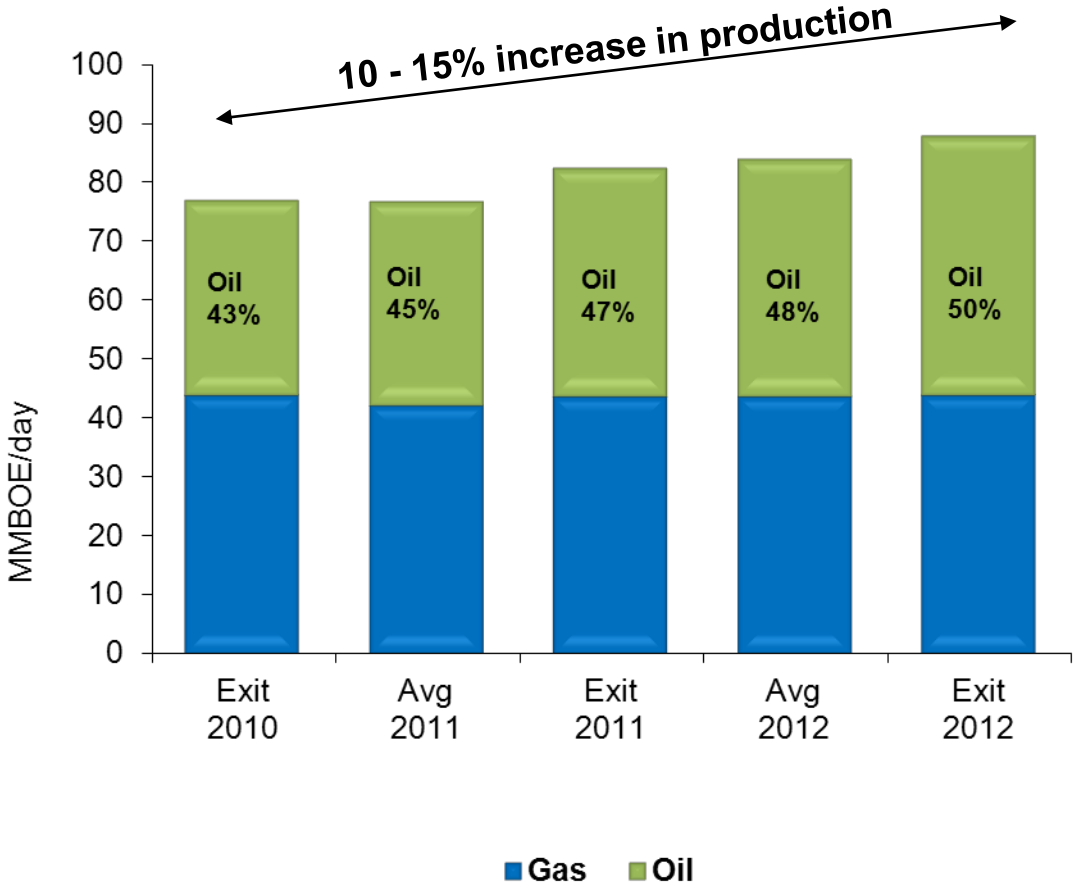
Total contingent resources of over 500 MMBOE is almost 2x existing booked reserves



* Dec 31, 2010 reserves adjusted to reflect June 2011 Marcellus asset disposition

- **Fort Berthold:**
  - 74,000 net acres
  - Growth potential of 20,000 BOE/day in 4 years
  - Additional upside potential in Three Forks
- **Waterfloods:**
  - Low decline cash generating oil production
  - Incremental drilling and enhanced oil recovery potential
  - 0-5% production growth in next 2 years
- **Marcellus Shale:**
  - 110,000 net acres, 60% operated
  - Production growth of 150 MMcfe/day by 2014
- **Unquantified upside (not included in contingent resources):**
  - **Deep Basin/liquids rich gas:**
    - Growing undeveloped land base of over 110,000 net acres in Montney, Stacked Mannville and Duvernay Shale
    - focused on delineation

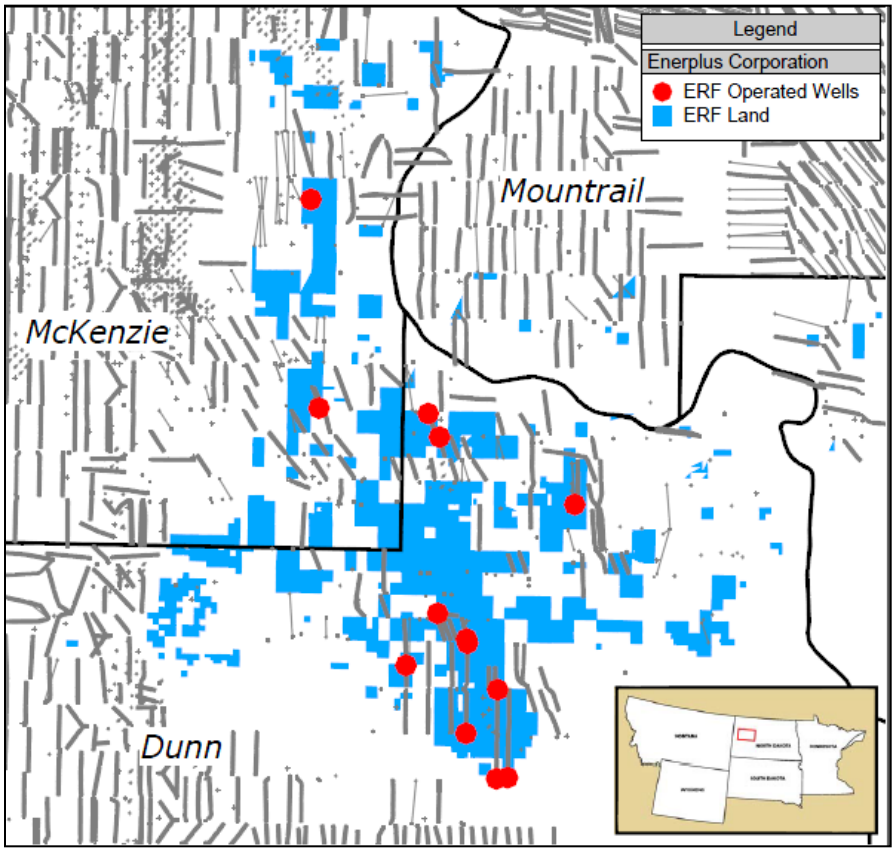
Production Growth



- Production growth of 10 – 15% over next 2 years
  - 5% debt-adjusted growth/year beyond 2012
- Oil production increases by over 20% through 2012

Crude Oil

North Dakota Bakken & Three Forks Potential



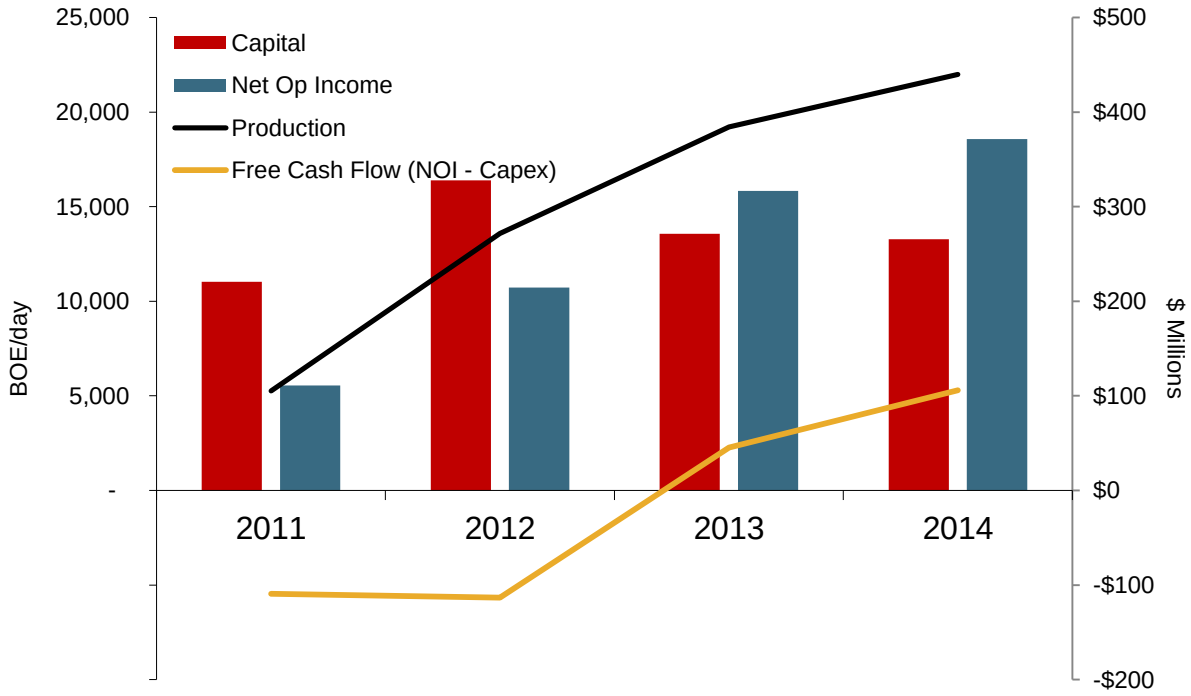
>90% operated, ~90% WI

Key Facts	
Net Acreage	74,500 (116 sections)
2P Reserves (Dec. 31, 2010)	22.4 million BOE
Bakken Contingent Resource	60 million BOE 90 drilling locations

- Upside potential from the Three Forks
- Concentrated acreage position (allottees) with long lease tenure
- $230 MM capital program planned for 2011 - currently running 4 rigs
- Plan to drill and complete 3 - 4 wells/month for remainder of 2011 – 22 wells
- Expect to double production to 10,000 – 12,000 BOE/day as we exit 2011

Significant Future Production Growth from Fort Berthold

Manageable growth, self-funding in 2 – 3 years

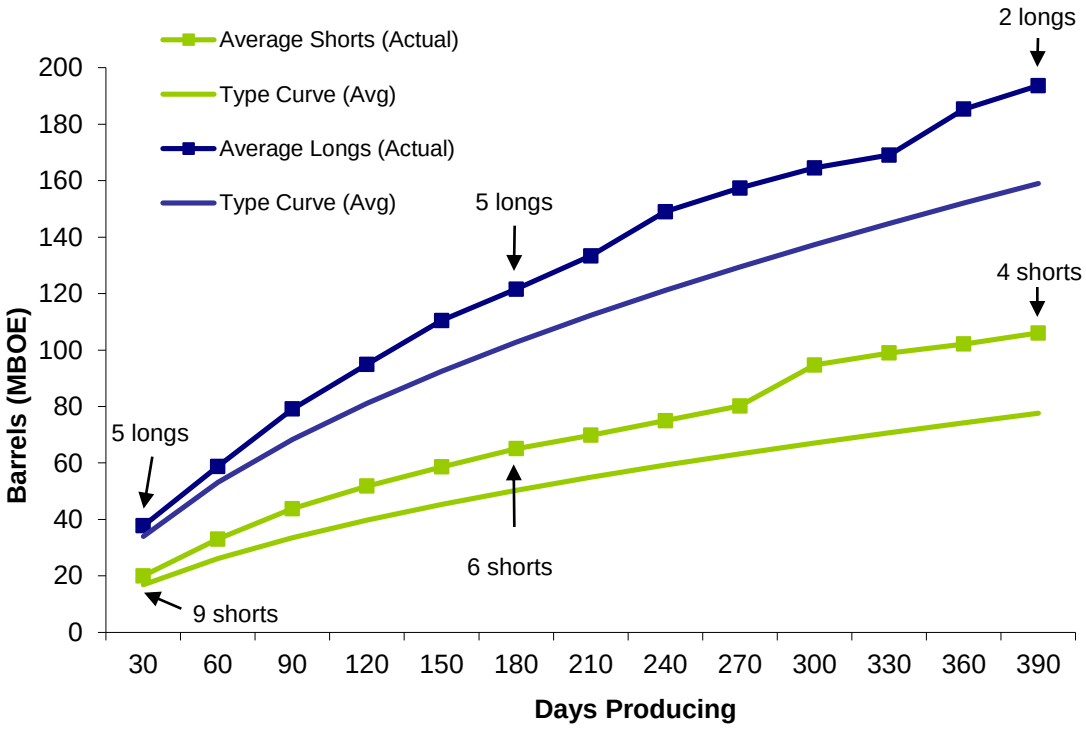


- Growth potential of 20,000 – 25,000 BOE/day by 2014
- Over $1 billion of capital over next 4 years with free cash flow projected in 2013
- Net operating income approaches ~$375 million by 2014
- Expected F&D cost of $10 - $21/BOE
- Recycle ratios of 2.1 – 5.5x

Assumes Sept 23, 2011 strip pricing

Economics are Exceeding Type Curve

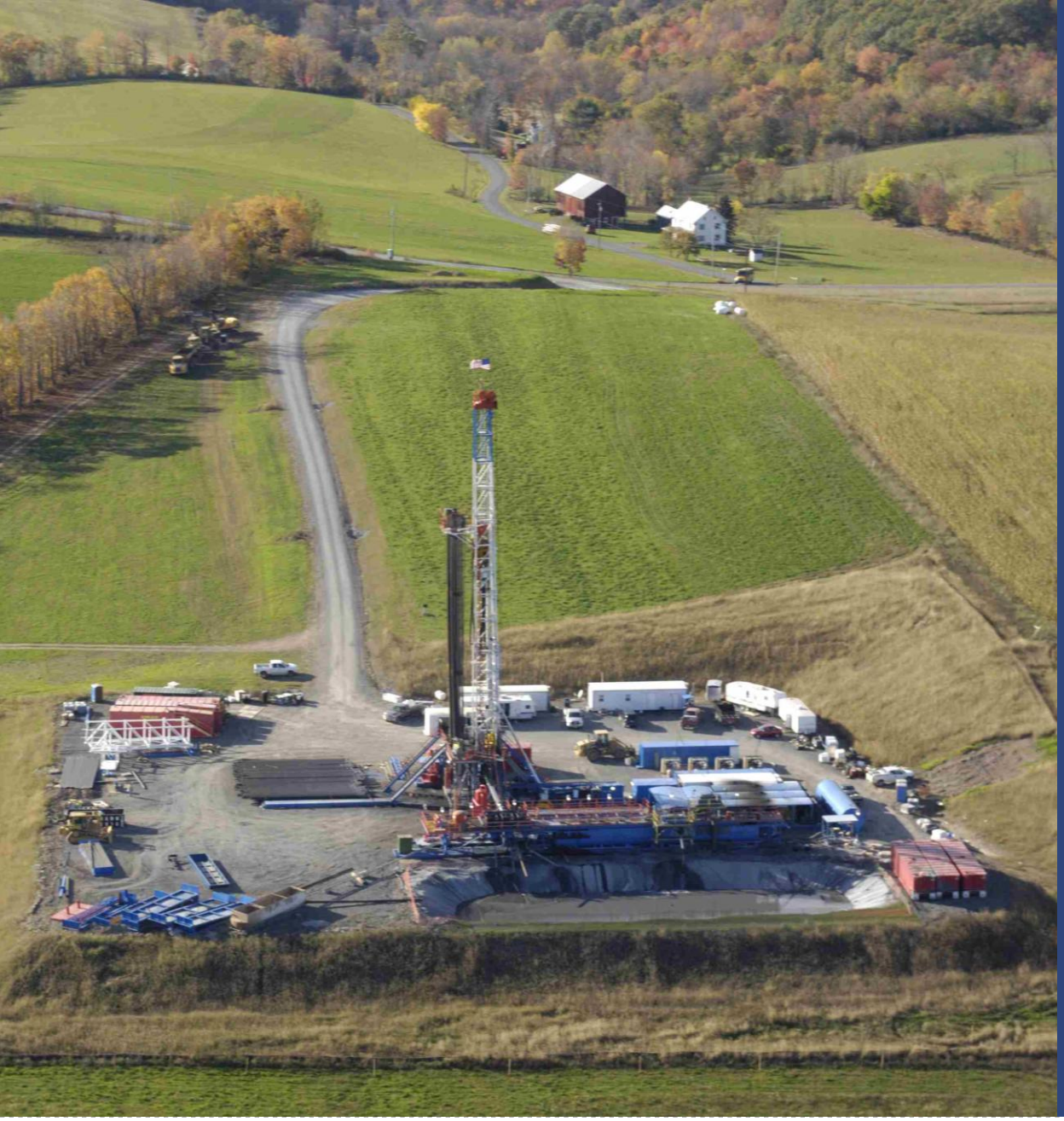
Long laterals are 30% ahead of the avg type well estimate
Short laterals are 45% ahead of the avg type well estimate



Long Laterals (9,000 ft. 24 frac stages), $8.7 MM/well		
	Type Curve	Actual 5 Well avg
Avg. 30 day initial production (bbls/day)	900 - 1,250	1,250
Expected Ultimate Recovery (Mbbls)	600 - 800	
Expected Net Present Value (12%, $MM)*	$8.0 - $14.0	
Expected Payout Period (years)	1.9 - 1.2	
Expected F&D ($/BOE)	$13.35 - $10.00	

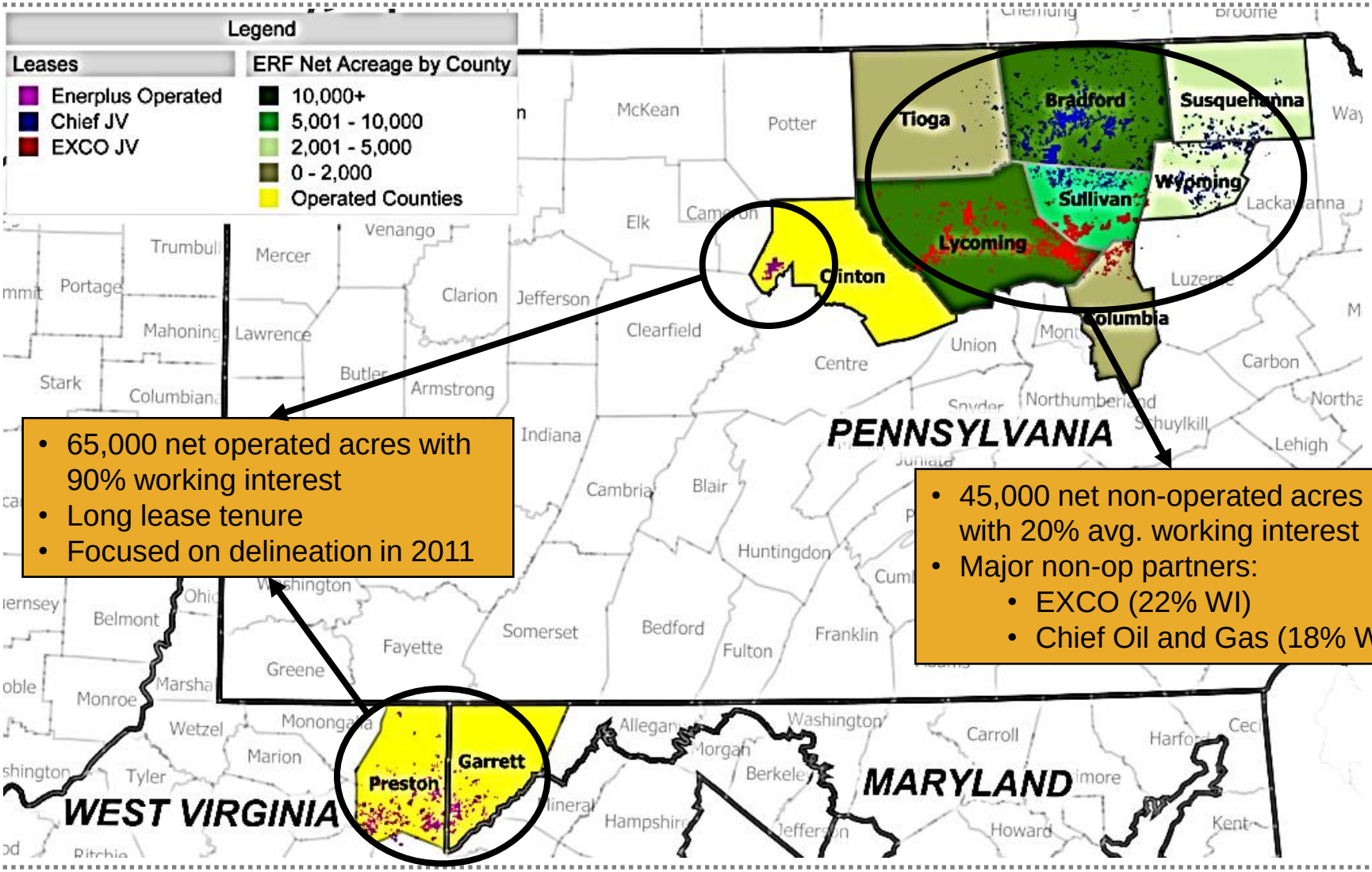
Short Laterals (4,500 ft. 12 frac stages), $6.7 MM/well		
	Type Curve	Actual 9 Well avg
Avg. 30 day initial production (bbls/day)	500 - 650	665
Expected Ultimate Recovery (Mbbls)	300 - 400	
Expected Net Present Value (12%, $MM)*	$1.7 - $4.7	
Expected Payout Period (years)	4.0 - 2.4	
Expected F&D ($/BOE)	$20.50 - $15.00	

*Economics based on Sept 23, 2011 forward price, production updated September 2011
Royalties average 20%, plus state production tax of 11.5%, op. costs of $4/bbl, differential assumption of $10 - $12/bbl



Natural Gas

Marcellus Shale Gas Overview

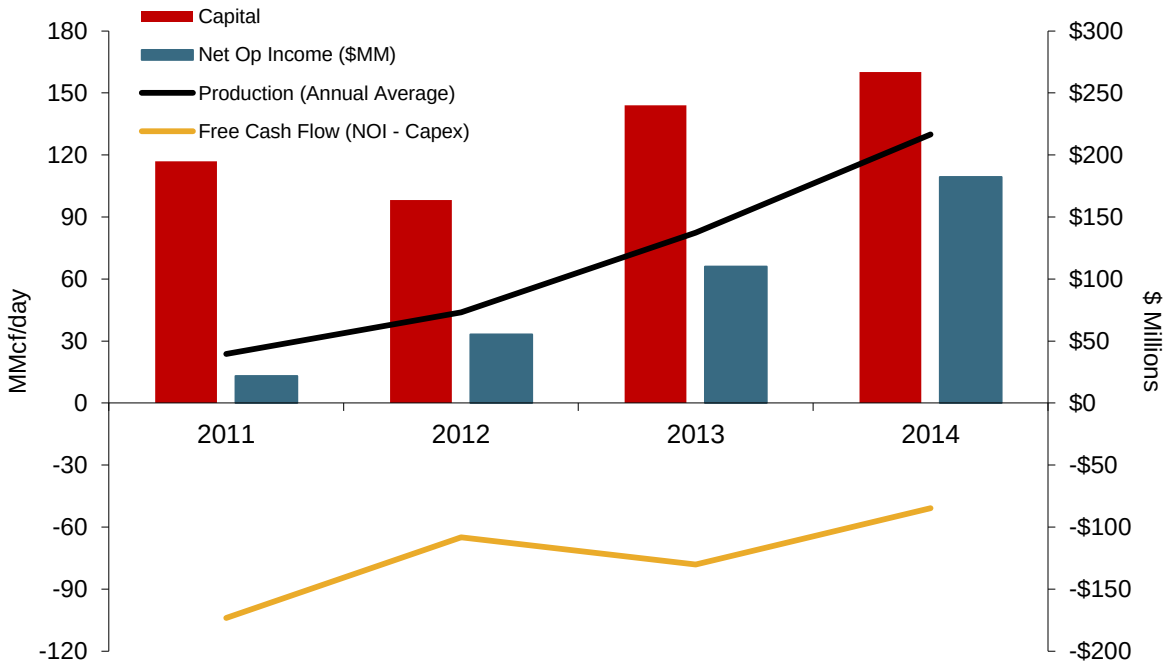


- 65,000 net operated acres with 90% working interest
- Long lease tenure
- Focused on delineation in 2011

- 45,000 net non-operated acres with 20% avg. working interest
- Major non-op partners:
  - EXCO (22% WI)
  - Chief Oil and Gas (18% WI)

Future Production Growth in the Marcellus

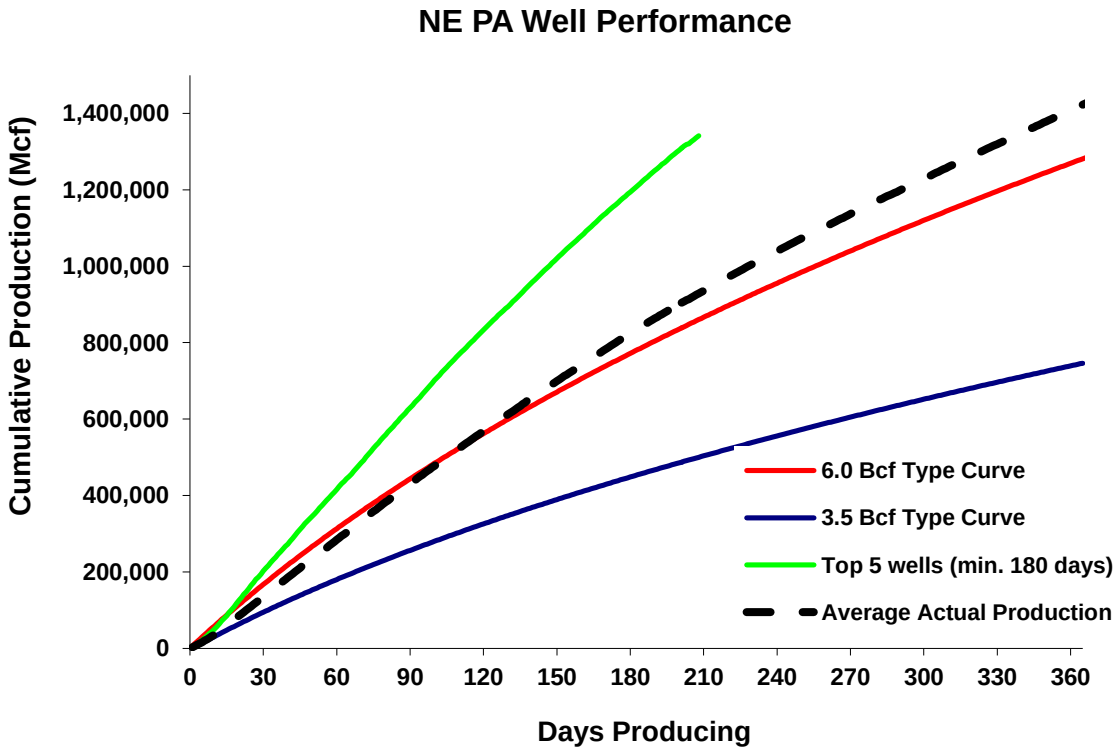
Sizeable resource capture provides opportunity for material development



- Current contingent resource estimate of 2.3 Tcf
  - would triple our corporate 2P natural gas reserves
- Production of ~150 MMcf/day by end of 2014
- Capital spending requirements of over $800 million in next 4 years
- Net operating income grows to almost $200 million by 2014
- Current netback of $3.75/Mcf

Improving Marcellus Performance

~90% of recent wells in the NE PA area are outperforming 6 Bcfe type curve

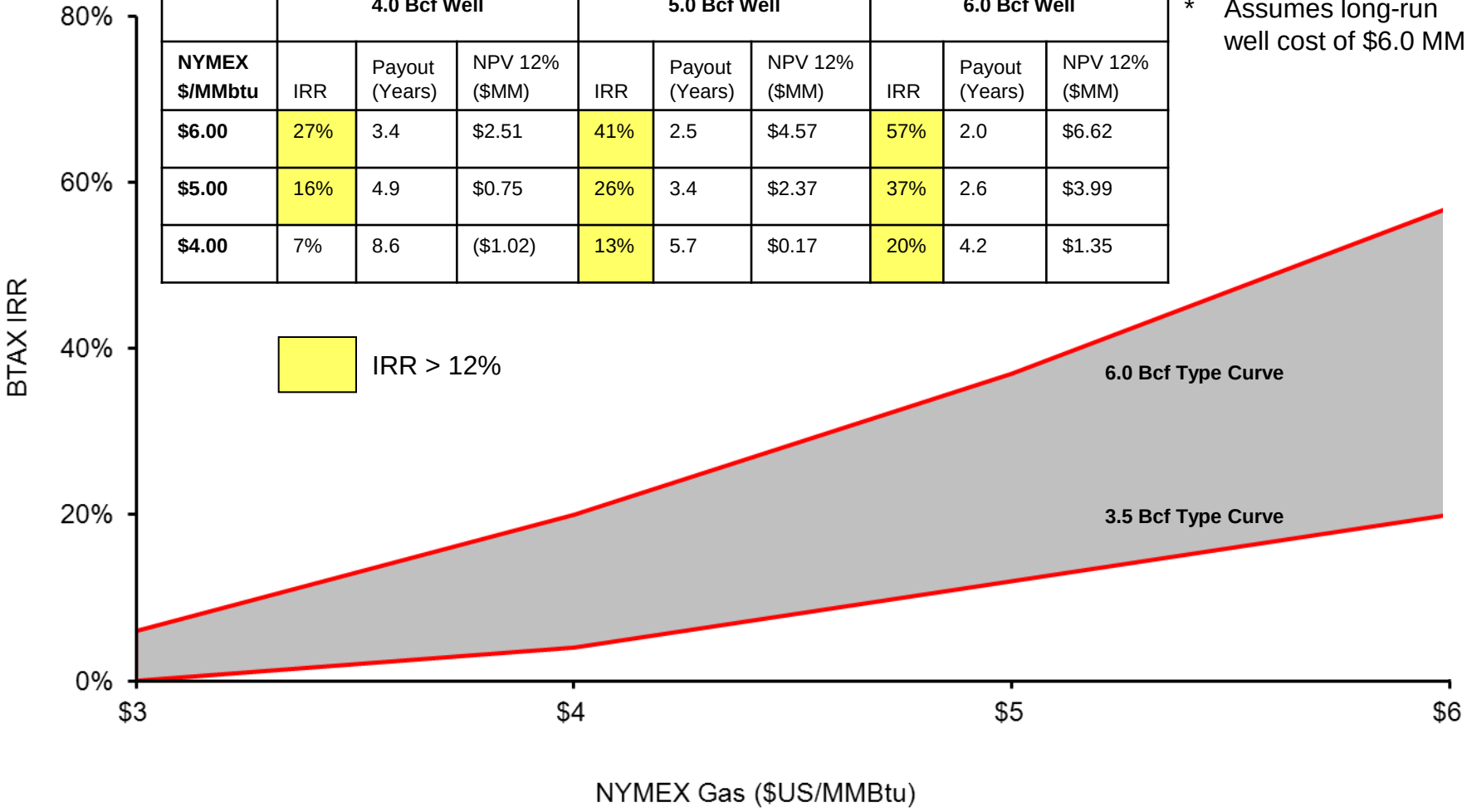


- Nearly 60 gross wells on production in NE Pennsylvania (Lycoming, Susquehanna and Bradford counties)
- Current production of 15 MMcf/day
- 169 gross wells (12.5 net) waiting on completion or tie-in

Marcellus Well Economics

	4.0 Bcf Well			5.0 Bcf Well			6.0 Bcf Well		
NYMEX $/MMbtu	IRR	Payout (Years)	NPV 12% ($MM)	IRR	Payout (Years)	NPV 12% ($MM)	IRR	Payout (Years)	NPV 12% ($MM)
$6.00	27%	3.4	$2.51	41%	2.5	$4.57	57%	2.0	$6.62
$5.00	16%	4.9	$0.75	26%	3.4	$2.37	37%	2.6	$3.99
$4.00	7%	8.6	($1.02)	13%	5.7	$0.17	20%	4.2	$1.35

* Assumes long-run well cost of $6.0 MM



Summary

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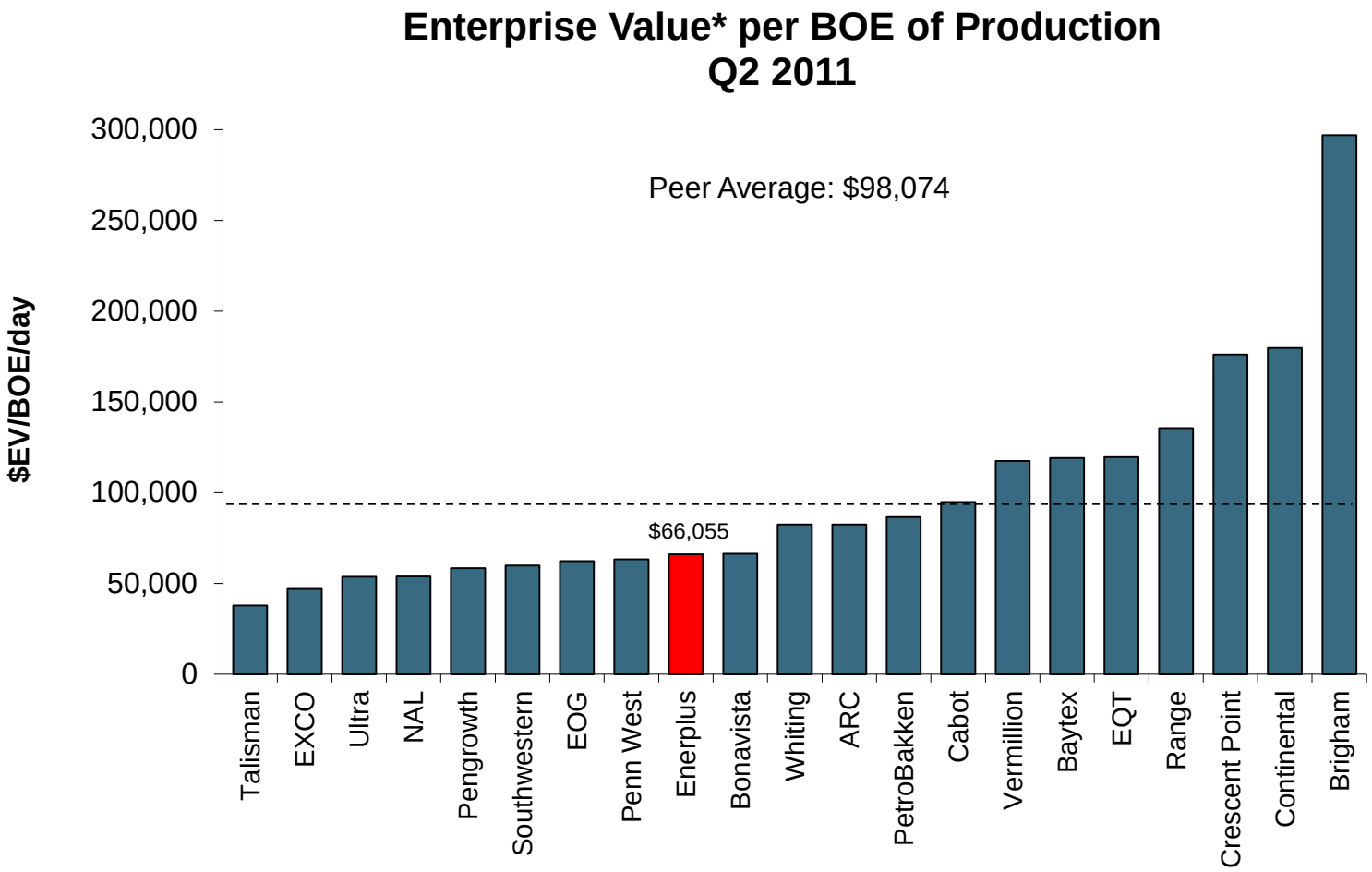
Positioned to Deliver Growth and Income

- High quality, diversified portfolio of low decline and growth potential assets
- Potential to double reserves through identified contingent resources in Bakken, Marcellus and waterfloods
- Near-term oil growth opportunity in North Dakota improving cash flow through 2012
- Growing undeveloped land position in liquids rich Deep Basin region with long lease tenure
- $1 billion unutilized credit facility supports development plans in 2011/2012

Current yield of over 8% with a compelling growth story

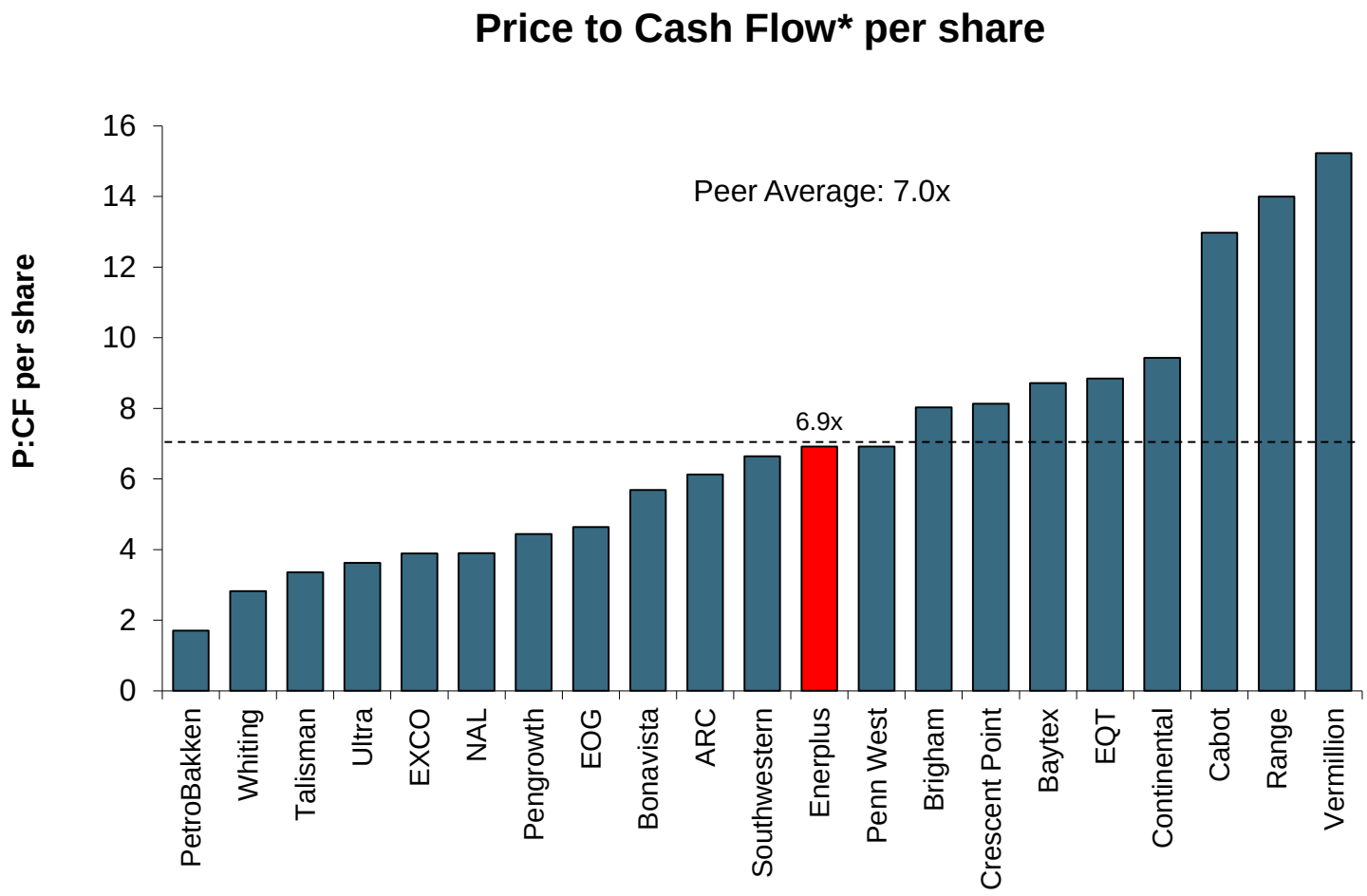
Supplemental Information

Attractive Valuation



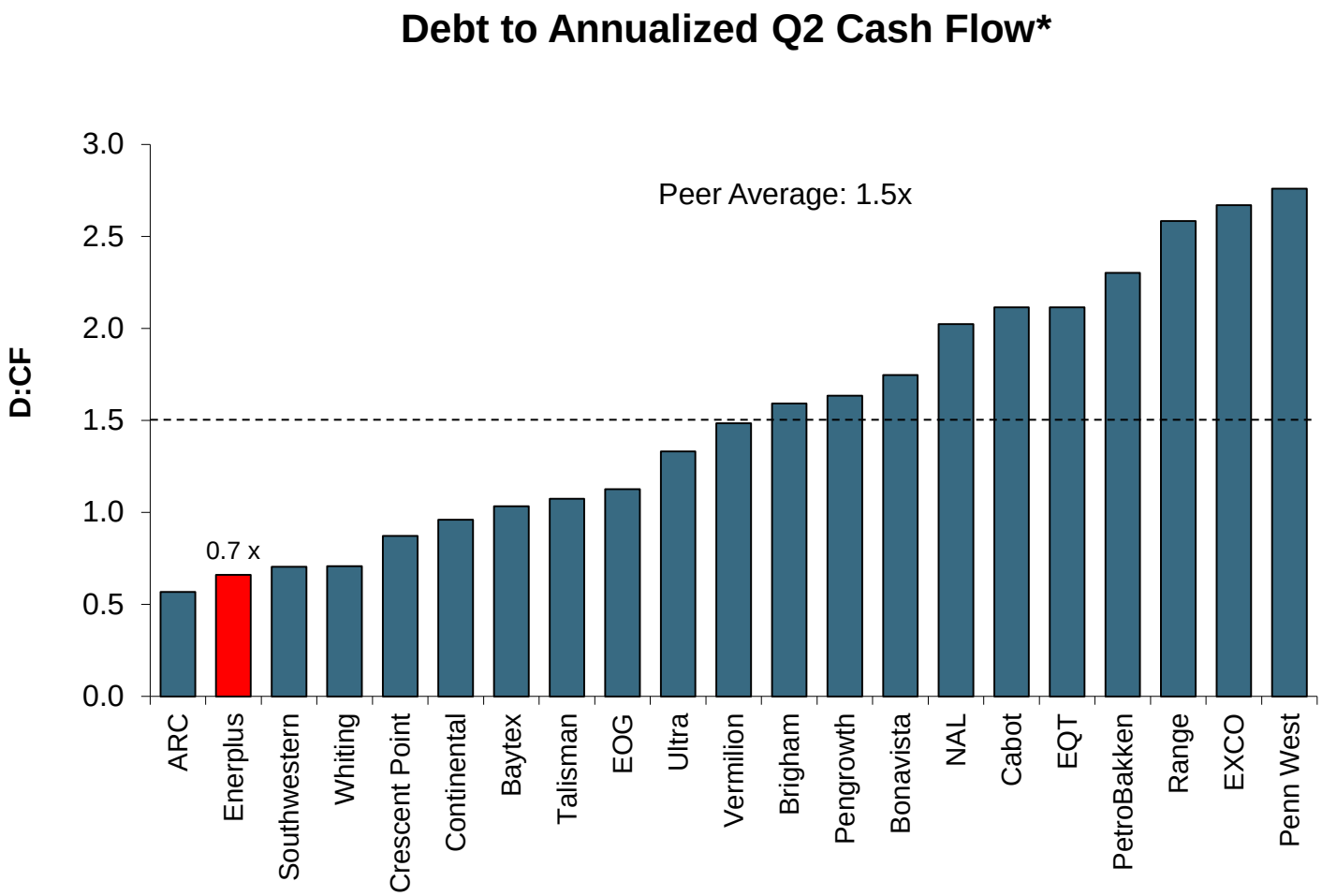
* Enterprise Value is Q2 2011 Debt plus Mkt Cap as of Oct 5 2011. Production is Q2 2011 average. Oct 5 2011 stock price.

Attractive Valuation



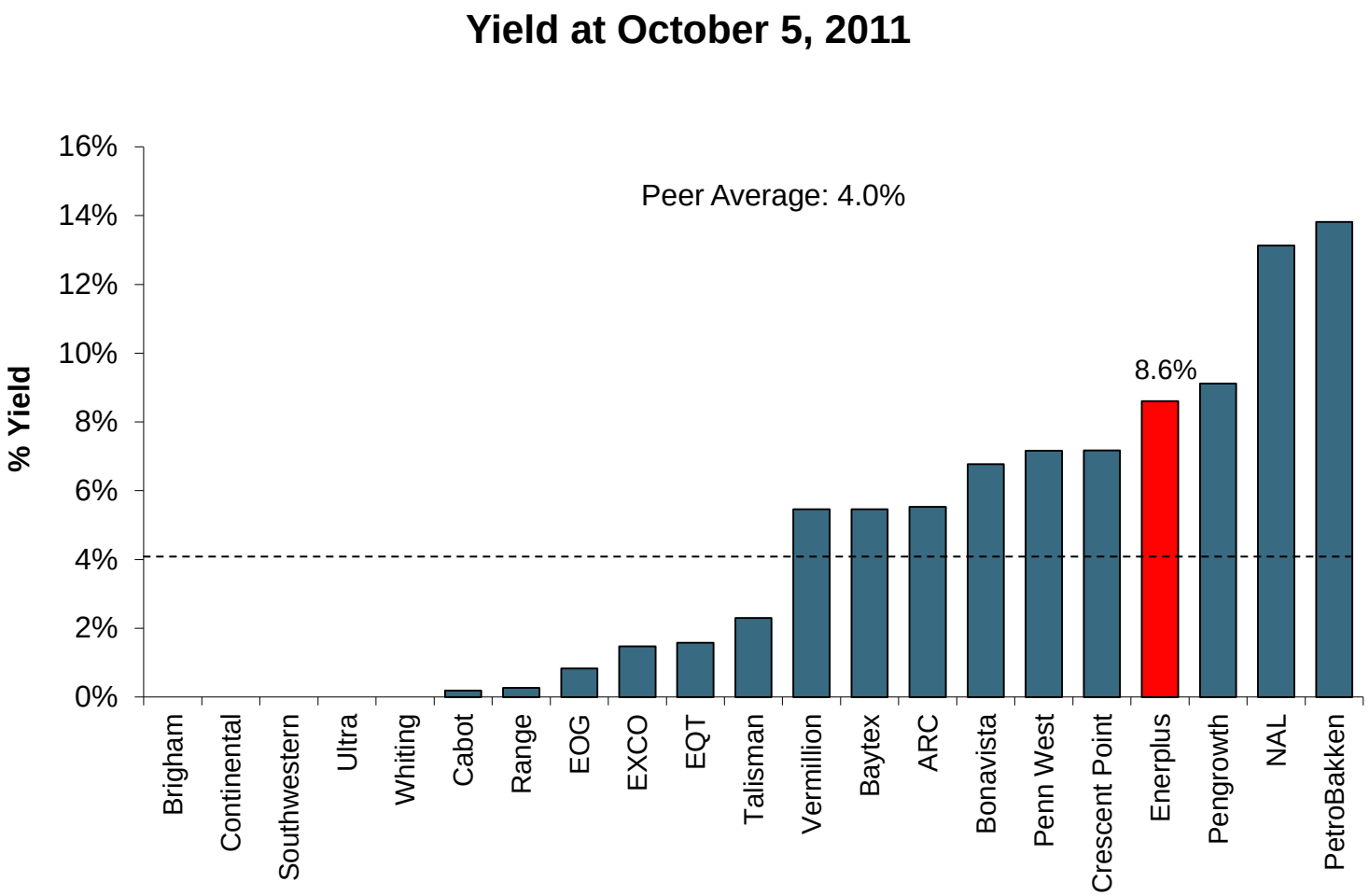
* Cash Flow from Operations is Q2 2011 annualized. Share prices are as of Oct 5, 2011.

Attractive Valuation



* Cash Flow from Operations is Q2 2011 annualized and Debt is as of Q2 2011

Attractive Valuation



* Current annualized dividend yield. Share prices are as of Oct 5, 2011.

Corporate Profile

• Enterprise Value (1)	$5.0 billion
• Average Daily Trading Value (Q3 2011)	$43.5 million
• 2011 Average Daily Production Guidance	76,000 – 78,000 BOE/day
• 2011 Exit Production Guidance	81,000 – 84,000 BOE/day
– Oil and Liquids Weighting	47%
• 2011 Development Capital Spending Guidance	$770 million
• Current Monthly Cash Dividend	$0.18/share
• Current Annualized Yield (at Oct 5, 2011)	8.6%

1. Market Cap. at Oct 5, 2011 plus Q2 2011 debt of $460 million

Q2 Results Impacted By Weather, But Still On Track

- Production of 75,383 BOE/day, held at Q1 2011 level
- $145 million capital spending
  - severe weather delayed execution of drilling programs
- Closed sale of a portion of our non-operated Marcellus for ~$568 million
  - captured gain of $272 million
  - retained concentrated 110,000 net acre position, 60% operated
- Increased land in emerging resource plays in Canada
  - 38,000 net acres in Duvernay liquids rich shale play
  - 14,000 net acres in two emerging oil prospects
  - total Montney position now 33,000 net acres

Revised 2011 Guidance

- Adjusted for Marcellus sale and impact of weather delays
- Increasing capital spending – replacing exit volumes and building incremental production in 2012
  - Inflation, weather impacts in H1 2011 and increased costs driving higher capital
  - Increasing non-operated Marcellus spending
  - Increased drilling in Canadian oil and liquids rich gas

	Original Guidance	**Revised Guidance**
Average annual production	78,000 – 80,000 BOE/day	76,000 – 78,000 BOE/day
Exit rate 2011 production	80,000 - 84,000 BOE/day	81,000 - 84,000 BOE/day
Production mix	*48% liquids*	*47% liquids*
Capital spending	$650 million	$770 million

Hedging

The following is a summary of the financial contracts in place at July 27, 2011 expressed as a percentage of our forecasted net production volumes:

	Crude Oil (US$/bbl)	
	April 1, 2011 – December 31, 2011	**January 1, 2012 – December 31, 2012**
Purchased Puts (downside protection)	-	$103.00
% of forecasted net production	-	3%
Sold Puts (limiting downside protection)	$56.50	$65.00
% of forecasted net production	12%	3%
Swaps (fixed price)	$87.27	$98.08
% of forecasted net production	61%	33%
Sold Calls (capped price)	-	$133.00
% of forecasted net production	-	3%
Purchased Calls (repurchasing upside)	$101.17	-
% of forecasted net production	12%	-

* There are no natural gas hedges in place at this point in time

2010 Year-End Reserves Summary

P+P Reserves	Oil Properties (MMBOE)	Gas Properties (Bcfe)	Total (MMBOE)
Opening Balance	171.8	1,039	344.9
Production	(12.7)	(105.4)	(30.3)
Divestments	(23.4)	(63.9)	(34.0)
Acquisitions	11	4.8	11.8
Additions	16.8	107.3	34.7
Revisions	(2.6)	(108.5)	(20.7)
Closing Balance	161.4	868.9	306.2

Note: 4 MMBOE of 2P reserves in Marcellus were sold in June 2011 - adjustment not reflected in total above

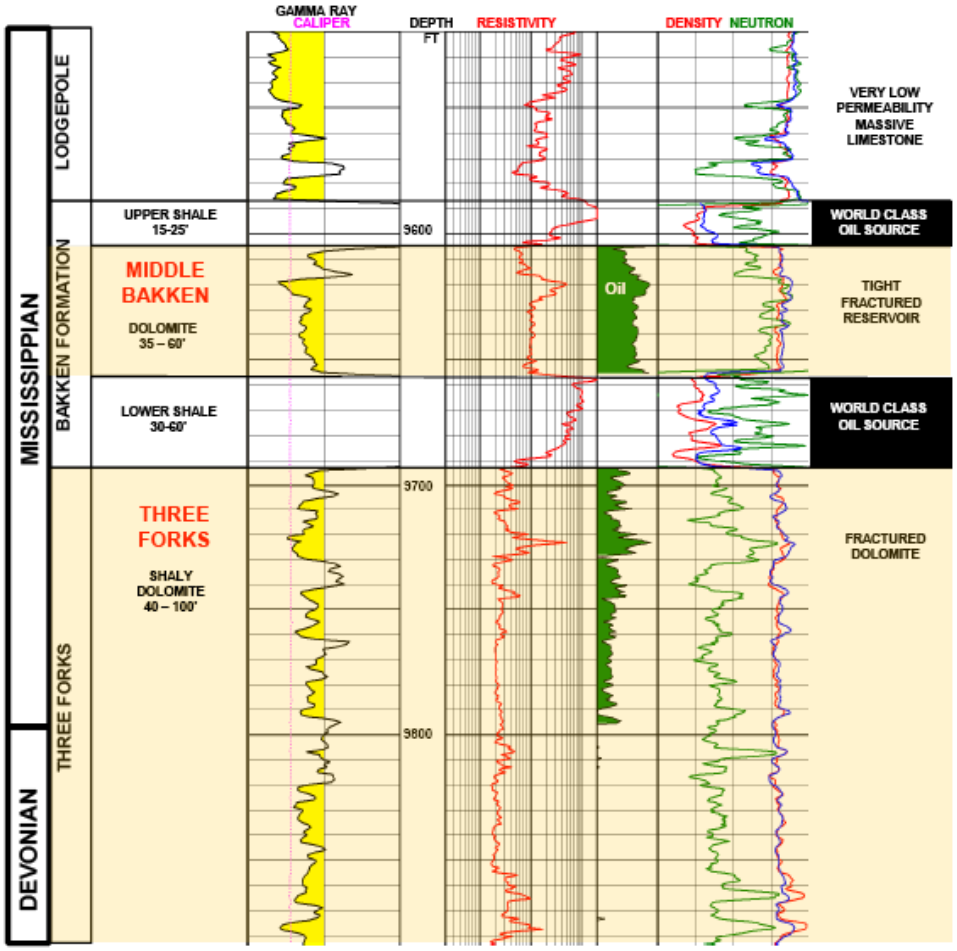
- Majority of decline in 2010 due to dispositions
- Development capital delivering results
  - All-in $17.46/BOE F&D before revisions
  - $10.74/BOE F&D at Ft Berthold
  - $1.64/Mcfe F&D at Marcellus
- Revisions primarily in shallow gas properties
  - 40% of revisions due to price decline
  - Performance revisions at Shackleton ~ $100 MM PV10% - 2% of year-end NPV

Supplemental Bakken Information

Fort Berthold Drilling Strategy

- 4 rigs currently under contract:
  - 2 “walking rigs” for 2 years
  - 2 conventional rigs through Q4 2011 and Q1 2012
- Service contracts in place support execution
  - Frac services and proppant agreements
- 2011 permits in place – building inventory for 2012 - 2013
- Testing optimal spacing and density
  - long-term development will focus on long horizontals
- Focus on multi-well pad drilling to minimize surface impact and tie-in costs

Bakken & Three Forks Geology

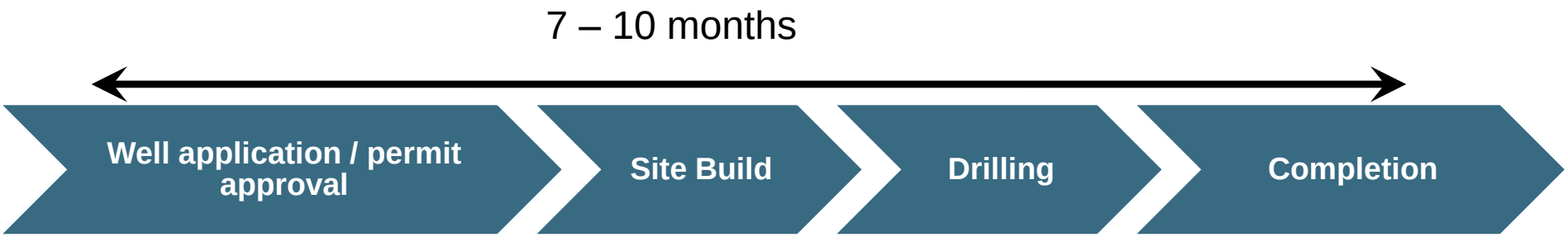


Source: Tudor Pickering Holt & Co.

	Middle Bakken	Upper Three Forks
Geological Age	Mississippian	Devonian
Depth	10,500 – 11,000 ft	10,600 – 11,000 ft
Thickness	35 – 45 ft	30 – 45 ft
Porosity	5 - 6%	6 - 10%
Overpressure	0.6 – 0.8 psi/ft	0.6 – 0.8 psi/ft
OOIP/640 acres	4 - 6 MMbbls	4 - 5 MMbbls

- Believe all our acreage is prospective for dual development
- Industry testing Three Forks proximal to our leasehold:
  - Helis Oil and Gas Dodge well offsetting our acreage to the west - produced 90 Mbbls in 4 months
  - Kodiak well offsetting our acreage to the east - 24 hour IP rate of 1,042 BOE/day; 30 day average of 603 BOE/day – with only 6 of 22 stages completed

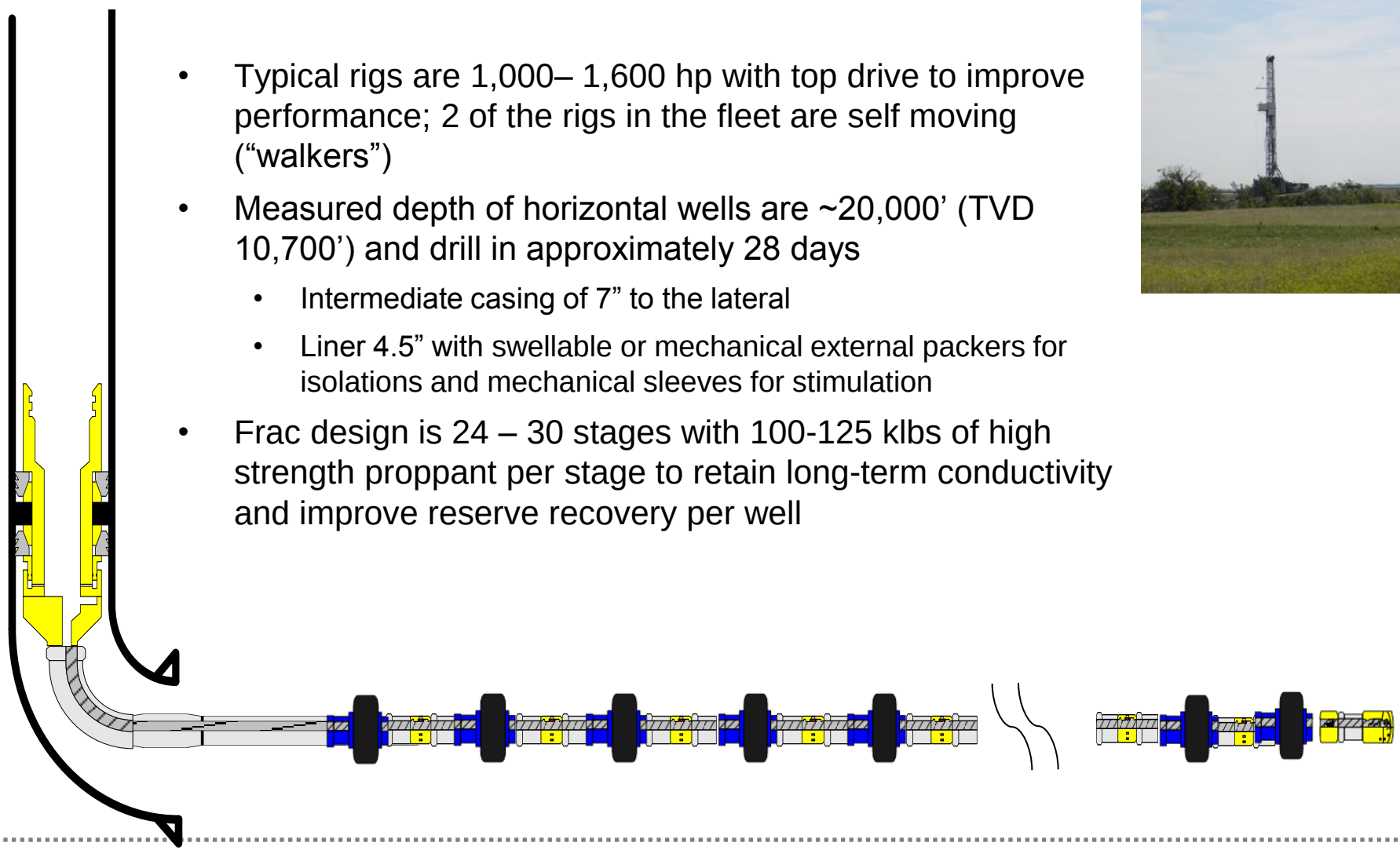
Well Timelines



Well application / permit approval	Site Build	Drilling	Completion
4 - 6 months	1 - 2 months	1 month/well	1 month
• Environmental assessment required on all federal lands • Have 38 permits in hand or very late stage approval • Have an additional 40 permits expected to complete EA process and be received by end of 2011 • Expect 50 additional permits submitted by year-end	Cannot begin building site until permit in hand	Multi-well pads “walking rig” are reducing drilling time	Have secured 42 days per quarter of frac services

Enerplus Well Design Methodology

- Typical rigs are 1,000– 1,600 hp with top drive to improve performance; 2 of the rigs in the fleet are self moving (“walkers”)
- Measured depth of horizontal wells are ~20,000’ (TVD 10,700’) and drill in approximately 28 days
  - Intermediate casing of 7” to the lateral
  - Liner 4.5” with swellable or mechanical external packers for isolations and mechanical sleeves for stimulation
- Frac design is 24 – 30 stages with 100-125 klbs of high strength proppant per stage to retain long-term conductivity and improve reserve recovery per well

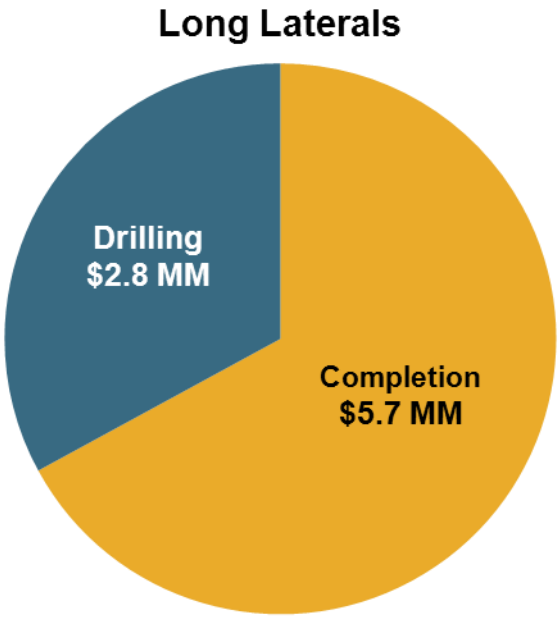


Source: Baker Tools

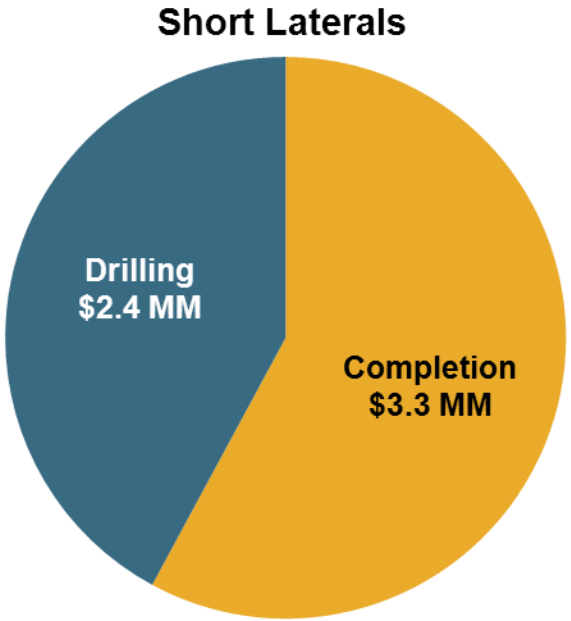
Fort Berthold Production – Gathering & Transportation

- Enerplus has committed to a field gathering system at the Fort Berthold Reservation which will:
  - Aggregate production at a central collection point off the Reservation that will provide flexible options for marketing the barrels
  - Gather and monetize both gas and liquids at market prices
  - Reduce the potential for shut in production due to varying weather, road conditions, and availability of trucking contractors
  - Provide some ability to better manage and dispose of produced water
  - Reduce the number of trucks moving on the Reservation which will reduce dust and road wear, and increase safety for the residents
- Current transportation/sales commitments of 2,000 bbls/day through 2012, increasing to 10,000 bbls/day for 2013/14

Fort Berthold Well Costs



Total Cost $8.5 MM

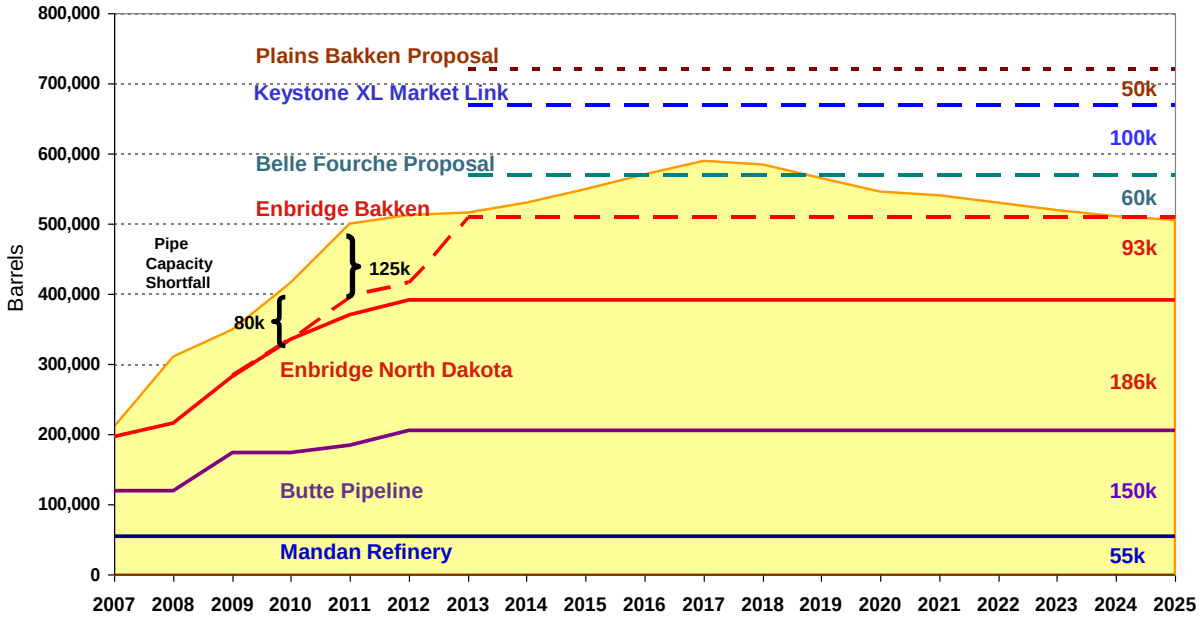


Total Cost $5.7 MM

Completions
- 125,000 lbs of proppant/stage, $1.3 - $1.5 MM for ceramic proppant
- Water: 2,500 – 3,000 bbls/stage, $3 - 6/bbl for trucking & disposal fees

Tie-in
- Additional $500,000
  Expect pad drilling will materially decrease tie-in costs

U.S. Bakken Infrastructure Capacity



Source: Internal company data and industry analysis

- Current U.S. Bakken production is ~400 MBOE/day
  - 500 MBOE/day in 2011
- Rail and trucking covers capacity shortfall

- Numerous new pipelines and expansions of over 300 MBOE/day are proposed to address the takeaway shortfall
- We control some pipeline capacity and also sell to intermediaries who hold capacity on existing pipelines or who have access to trucking/railing facilities
- Additional 3rd party railway takeaway capacity proposal being considered

Supplemental Waterflood Information

Waterflood Upside - Improving and Enhancing Oil Recovery

Asset	OOIP (MMBOE)	Total Recovered (MMBOE)	2010 YE 2P Reserves (MMBOE)	Contingent Resource (MMBOE)		
				IOR	EOR	Total
Medicine Hat, AB	217	17	16.5	6.5	21.7	28.2
Giltedge, AB	126	16	10.4	4.0	12.6	16.6
Freda/Skinner Lake, SK	75	9	10.2	6.6	0	6.6
Cadogan, AB	45	4	2.1	3.6	0	3.6
Virden/Daly, MB	283	78	8.5	3.1	0	3.1
Neptune, SK	24	4	2.6	2.4	0	2.4
Sub-Total	**770**	**128**	**50.3**	**26.2**	**34.3**	**60.5**

- Other waterflood assets with IOR/EOR upside:
  - Pembina 5-way
  - Gleneath
  - Joarcam
  - Progress/Pouce Coupe

Contingent resource estimate represents a 75% increase to 2P waterflood reserves if fully booked

Note: There are other waterflood properties that contribute to reserves and production within this resource play that are not included above

The Stages of Oil Recovery

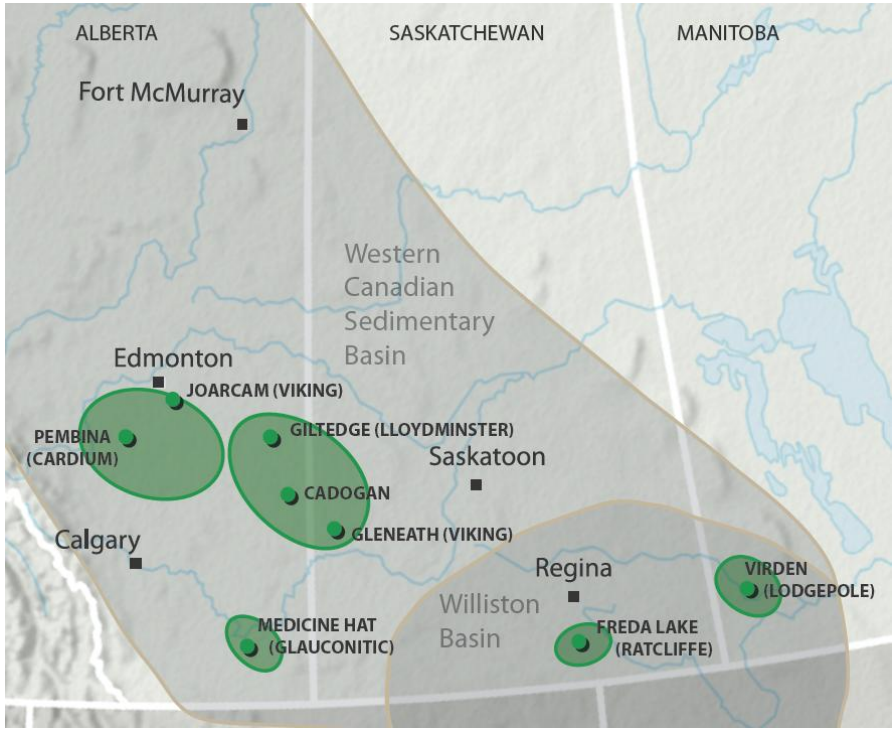
Stage	Implications

Waterflood
• Injecting high pressure water
	• Hold production steady, grow recovery
	  • Facilities in place
	  • Maintenance costs increasing with age

Improved Oil Recovery (IOR)
• Optimizing waterfloods through sweep, pattern or voidage improvements
• Conducting lab work to screen for EOR potential
	• Grow production & recovery
	• Spending capital up front for future benefit
	  • Expand facilities
	  • Convert vertical producers to injection
	  • Drill horizontal producers
	  • Maintenance costs improved

Enhanced Oil Recovery (EOR)
• Reducing residual oil saturation and improving sweep efficiency
	• Grow production and recovery
	• Spending capital up front for future benefit
	• Increasing op costs
	  • Facilities for polymer injection
	  • Polymer

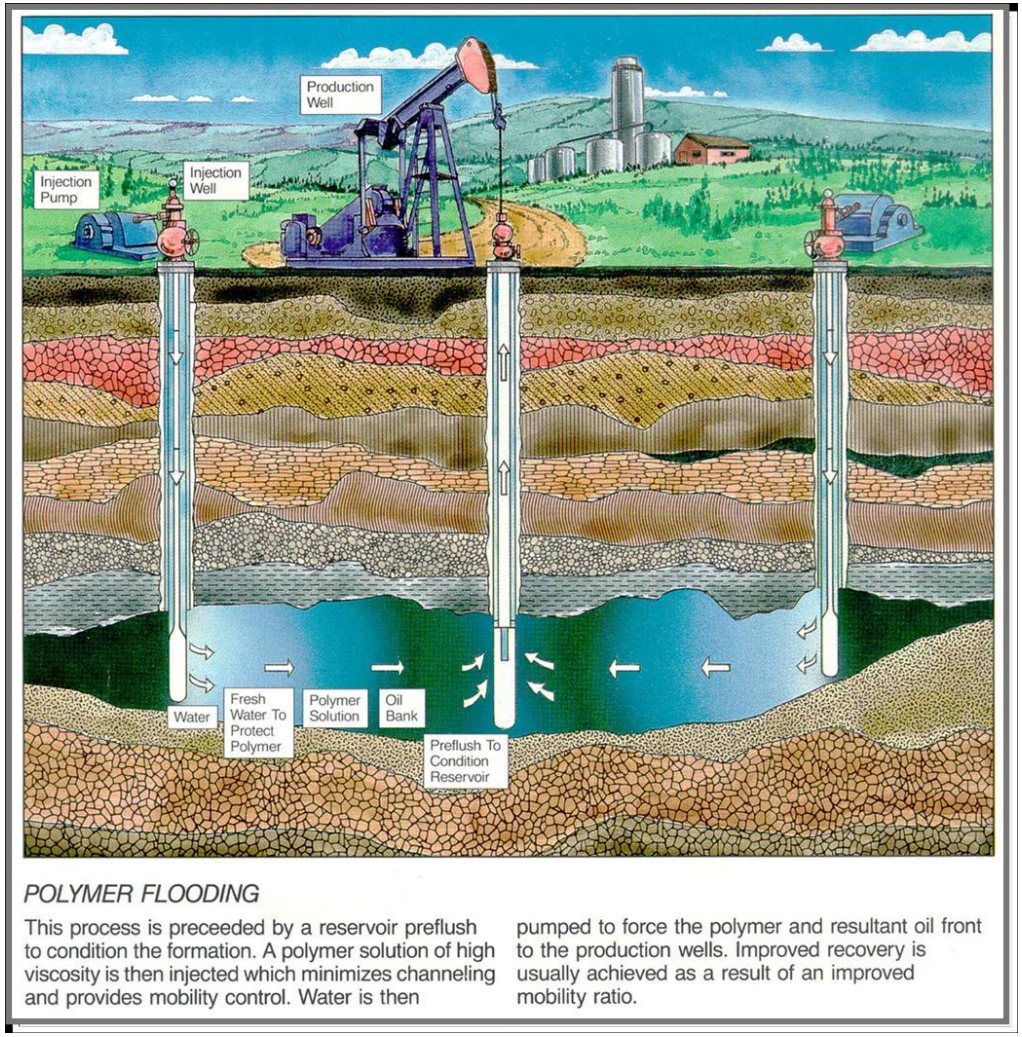
Low Decline, Crude Oil Waterfloods



Key Facts	
P+P Reserves (Dec 31, 2010)	83.7 MMBOE (booked to 27%)
Best Est. Contingent Resources	60.5 MMBOE
Recovery to date	21%
Average Oil Quality	30° API
2011E Annual Production	13.5 – 15.0 MBOE/day 18% of company total

- Original oil in place of ~1.1 billion BOE within a portion of waterflood portfolio
- Significant asset base of 18 properties producing from medium and light oil formations
- Free cash flow supports dividend and growth strategy
- Underlying base decline rate of ~10%
- Significant future potential from IOR and EOR

Polymer Flood



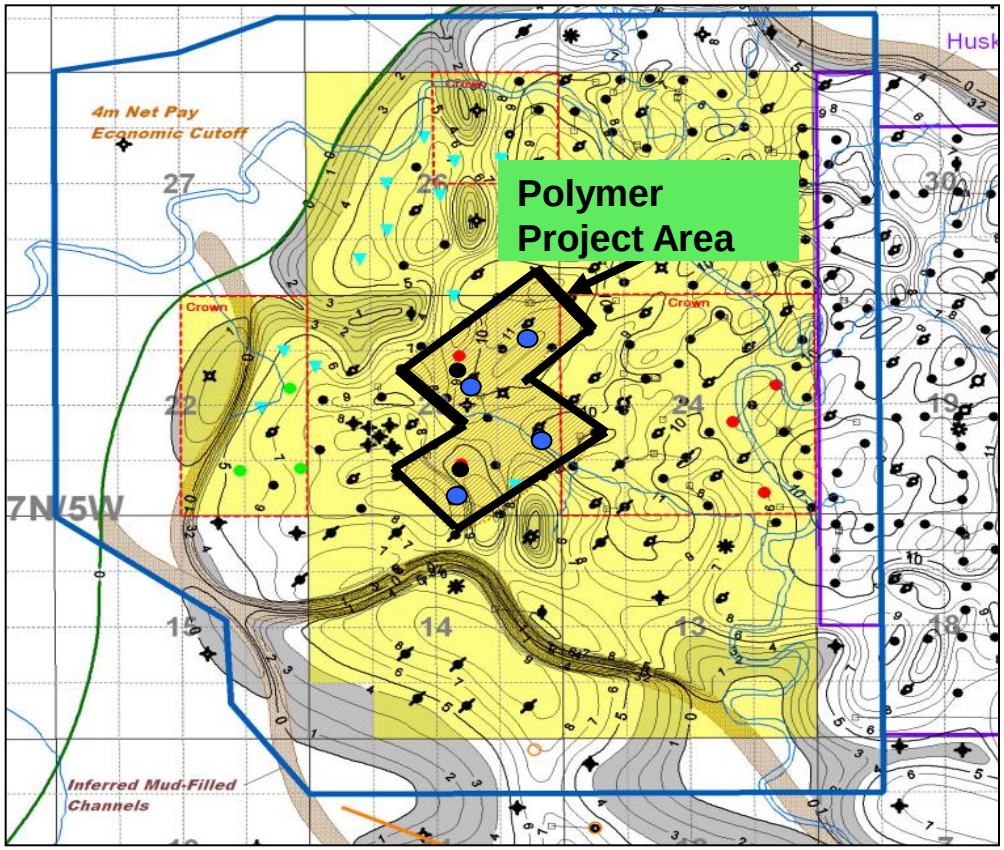
POLYMER FLOODING

This process is preceeded by a reservoir preflush to condition the formation. A polymer solution of high viscosity is then injected which minimizes channeling and provides mobility control. Water is then pumped to force the polymer and resultant oil front to the production wells. Improved recovery is usually achieved as a result of an improved mobility ratio.

Source – Oil and Gas Journal

- Polymer is chemical additive that increases viscosity of injected water
  - Reduces residual oil saturation
  - Improves sweep efficiency
- Works best with heavier crudes in high permeability reservoirs with low waterflood recovery factors
- The first identified projects are at Giltedge and Medicine Hat Glauc C
- Typical expected recovery improvement is ~8 - 15% (rule of thumb is 30% of the projected waterflood recoverable oil)

Giltedge – EOR Project Area



Polymer injection wells

Indicative project economics:

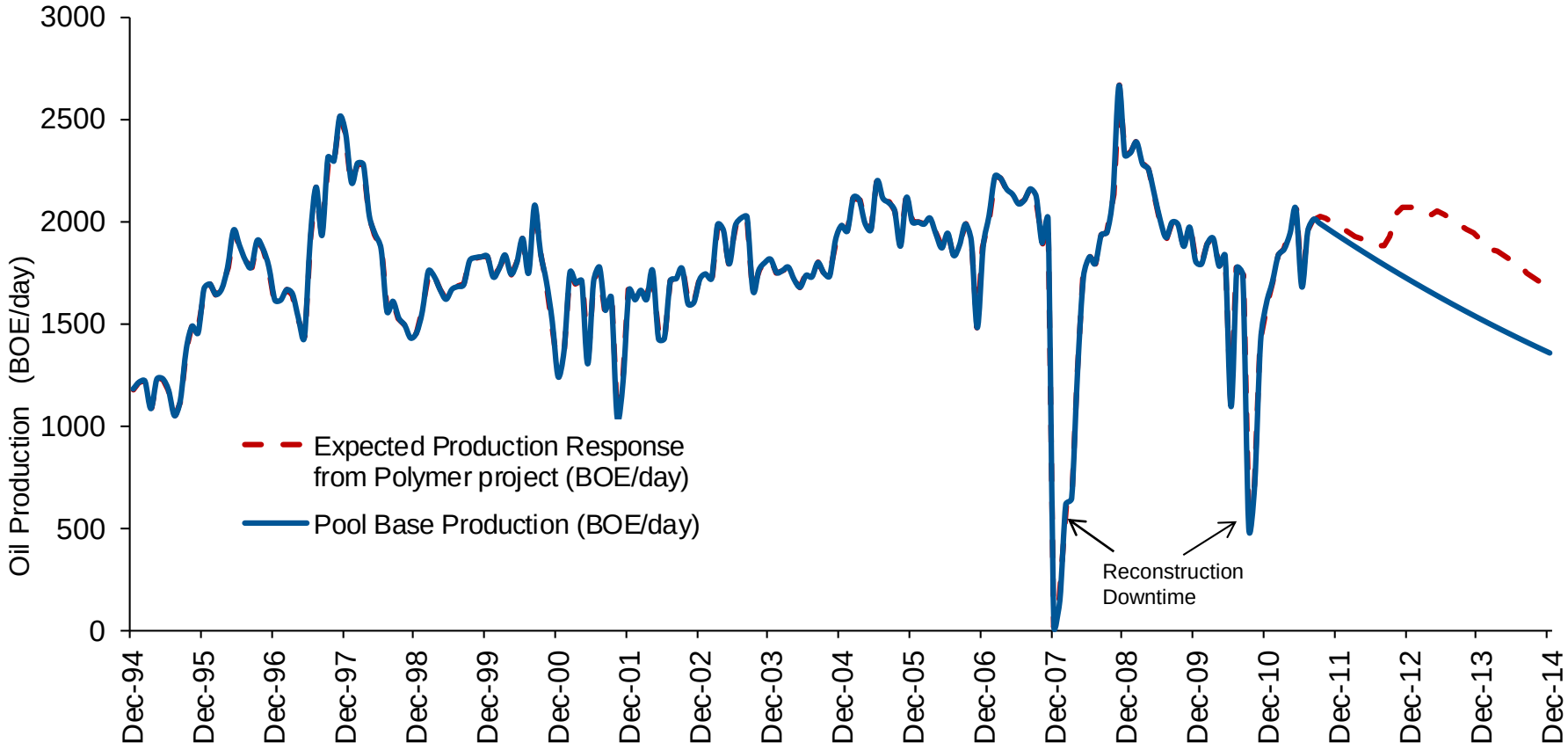
- NPV @ 10%: ~$20 million
- IRR: 25 - 40%

Key Facts	
OOIP	126 MMBOE
Recovery Factor to Date	~13%
Cumulative Production	16.4 MMBOE
P+P Reserves (Dec 31, 2010)	10.4 MMBOE (booked to 21%)
Best Est. Contingent Resource	16.6 MMBOE (~13% incremental recovery)
Oil Quality	14° - 20° API
2011E Avg. Production	1,800 BOE/day oil, 97% water cut

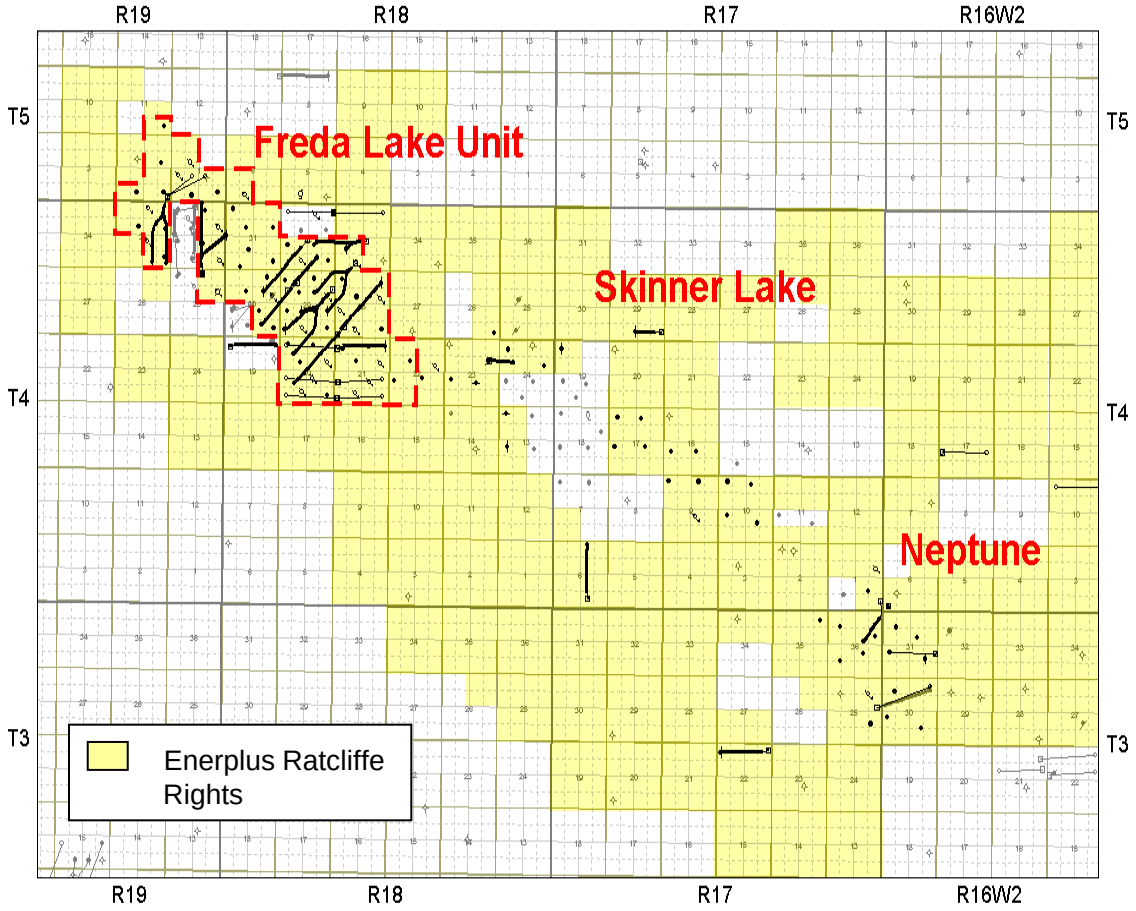
- Historical decline: ~13%
- IOR and EOR contingent resource potential of 16.6 MMBOE, over 60% more than current 2P reserves
- Potential incremental reserve adds of 0.8 – 1.5 MMBOE in project area (4-8% incremental recovery)
- Production in project area could increase 2 - 3 times from current levels over next 20 - 30 months
- Currently injecting polymer and expect to see impact by year-end

Giltedge Production

Production growth potential through EOR/polymer project



Freda/Skinner/Neptune, SK - Ratcliffe & Bakken

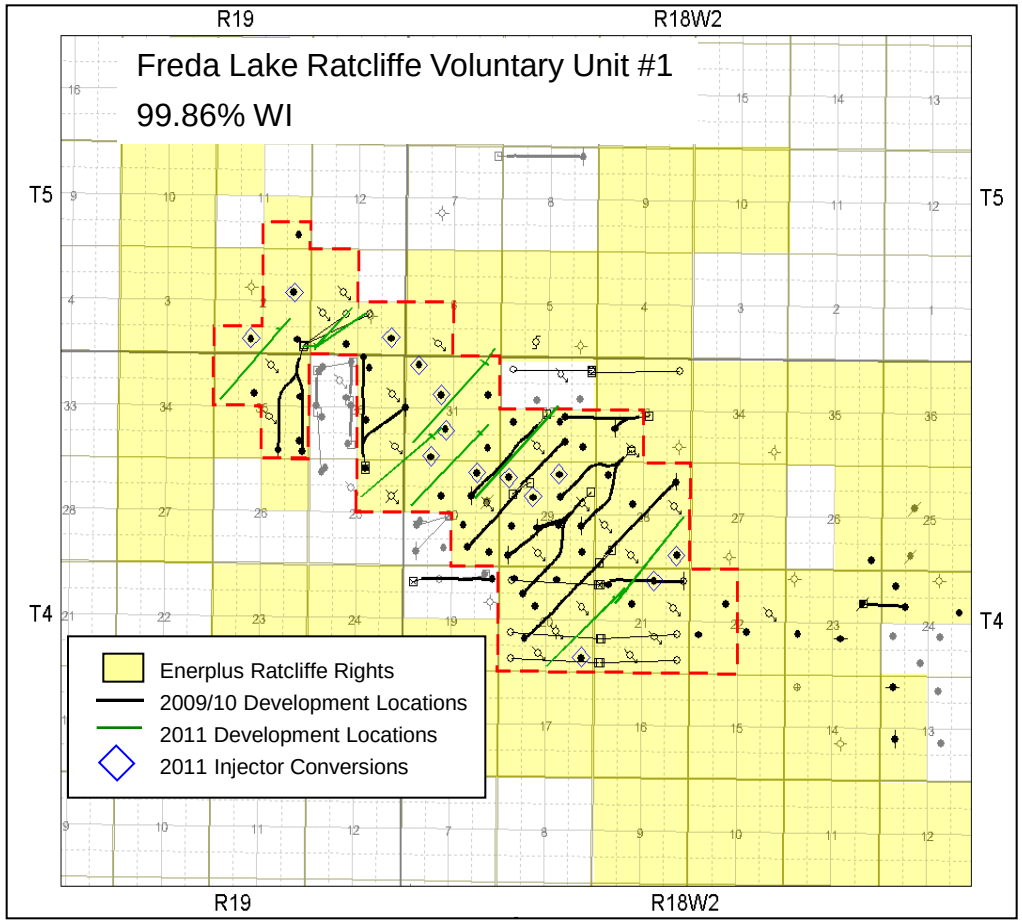


Average working interest > 98%

Ranging from 70 –100%

- Approximately 115,000 net acres of Ratcliffe rights
- Majority overlay Bakken rights
- Oungre/Ratcliffe zones at a 1,600 - 1,800 metre depth
- Current Ratcliffe production ~1,900 BOE/day
- Internal best estimate contingent resource of 9.0 MMBOE, 70% of our booked 2P reserves
- Current reserves are booked to 26%
- Bakken results to date disappointing – further analysis required
- Positive success in the Ratcliffe

Freda Lake Ratcliffe Unit



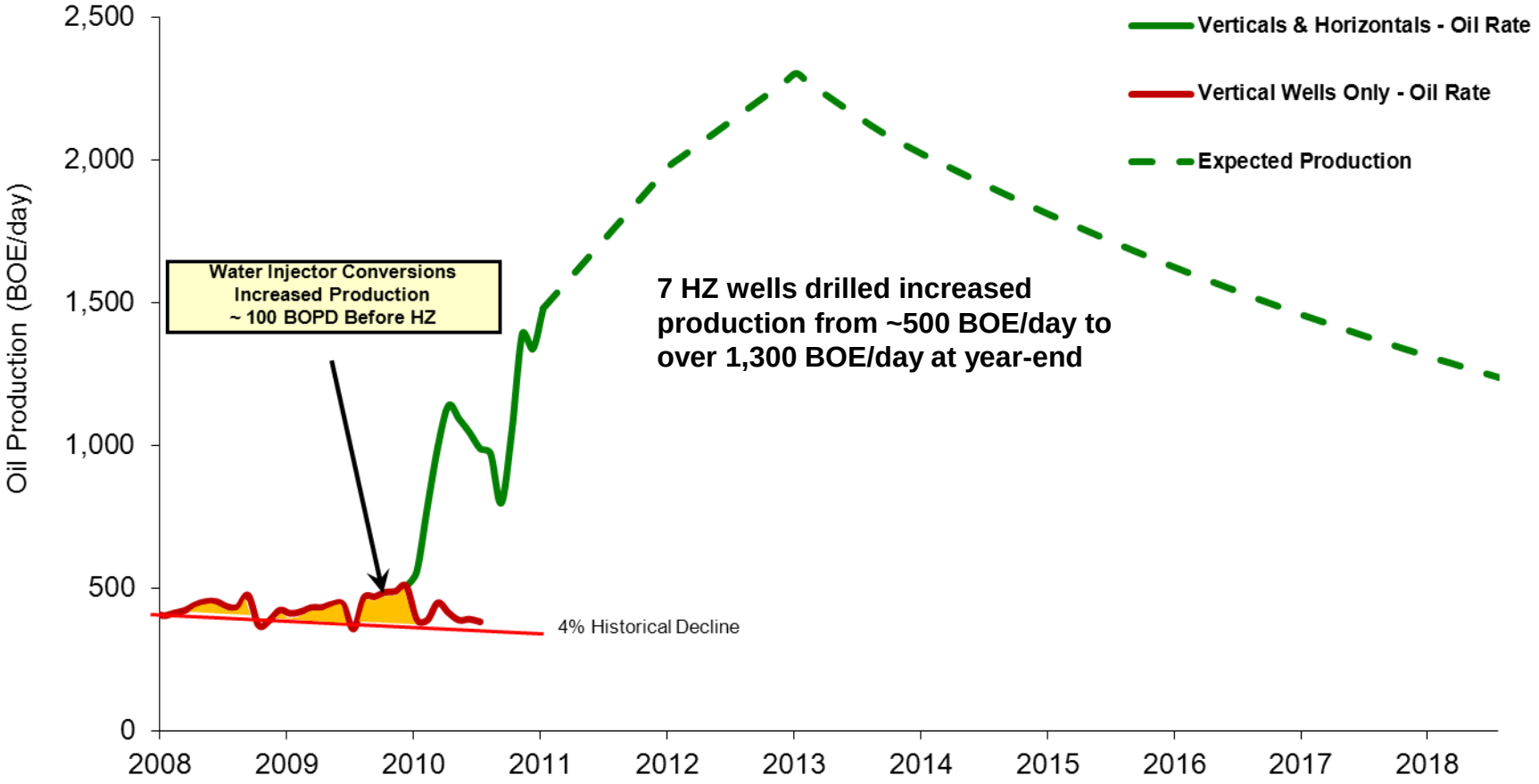
Key Facts	
OOIP	55 MMBOE
Recovery Factor to Date	~14%
Cumulative Production	8 MMBOE
P+P Reserves (Dec. 31, 2010)	10.2 MMBOE (booked to 31%)
Best Est. Contingent Resource	2.3 MMBOE (+4% RF)
Oil Quality	32° API
2011E Exit Production	2,100 BOE/day oil (+45% vs 2010)

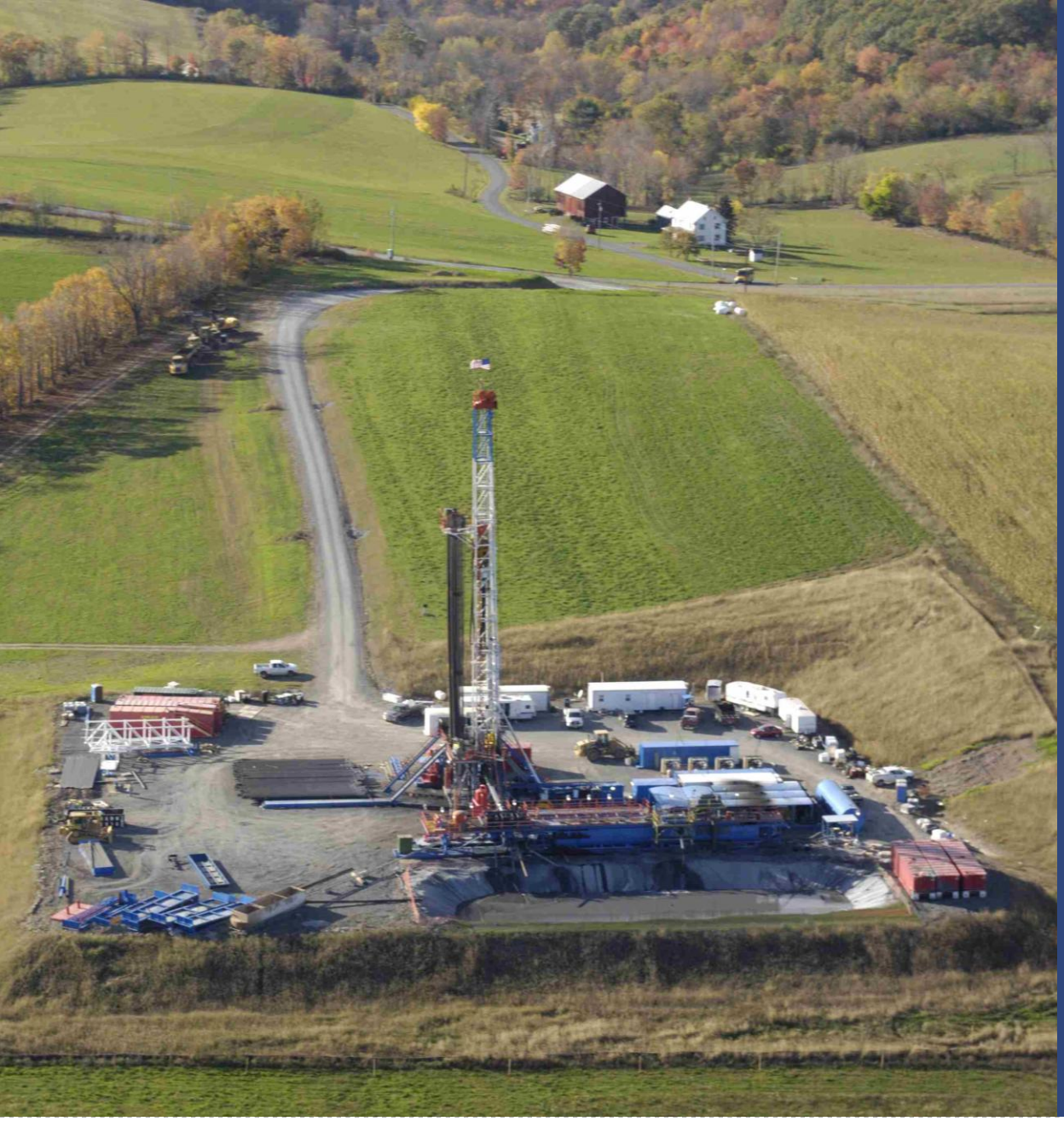
- Discovered 1967 & developed on 80 acre vertical well spacing, acquired in 2003
- Peripheral waterflood implemented mid 1980's
- New wells attract lower royalties
- Historical decline ~ 4%, RLI ~40 years
- Injection conversions increasing oil production from surrounding producers
- Recent single and dual leg HZ wells producing at 150-300 bbl/day with 37-65% water cuts vs a previous pool average of over 90%

Horizontal wells and waterflood optimization unlocked major resource

Freda Lake Ratcliffe Unit Production

Up to 14 more HZ wells to drill in the unit





Supplemental Marcellus Information

2011 Marcellus Plans

- 2011 capital program of $195
- Non-operated activity – focused in NE PA region:
  - EXCO – currently running 3 rigs with all activity focused in Lycoming County
  - Chief – continue to run 3 rigs with activity focused in Bradford and Susquehanna counties
- Operated activity:
  - Running 1 rig and expect to drill 5 gross wells focused on delineating resource
    - Currently drilling second well in Clinton County, PA and spud first of 3 wells planned in Preston County, WV

Over 40% internal rate of return expected on majority of Marcellus capital projects

Marcellus Well Timeline

6 – 8 months

Well application / permit approval	Site Build	Drilling	Waiting on Frac Crews	Fracing
45 – 60 days in PA	45 – 90 days	25 – 35 days/well	30 - 60 days	7 - 14 days
• 30 – 45 days in WV • Assumes water sources permitted • Current regulations	• Cannot begin building site until permit in hand • Depends on time of year	• Multi-well pads • “self-skidding” rigs help reduce drilling time	• Shortage of frac fleets relative to basin-wide drilling activity	

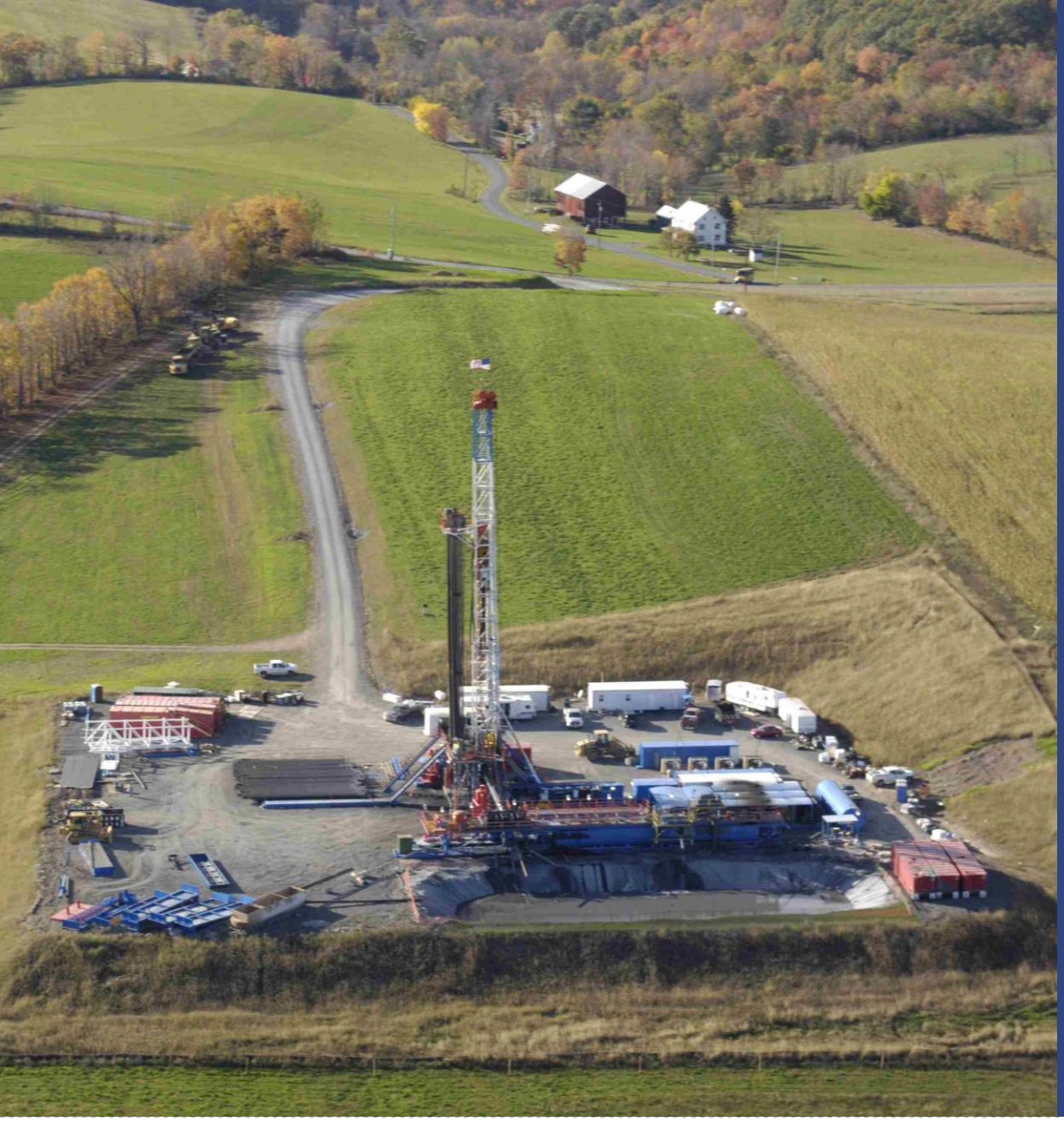
Note: Timeline excludes well “resting” and tie-in to gathering systems

Moving Natural Gas Out of the Marcellus

- Enerplus has taken several steps to ensure we can move our growing Marcellus gas production to market:
  - Entered into longer term (5 years +) firm “must take” contracts with creditworthy substantial end users of the natural gas who:
    - hold firm capacity on the various interstate pipelines (Transco, Tennessee)
    - have storage capacity and trading ability
  - These contracts have flexibility to increase delivered volumes as we bring production to pipe:

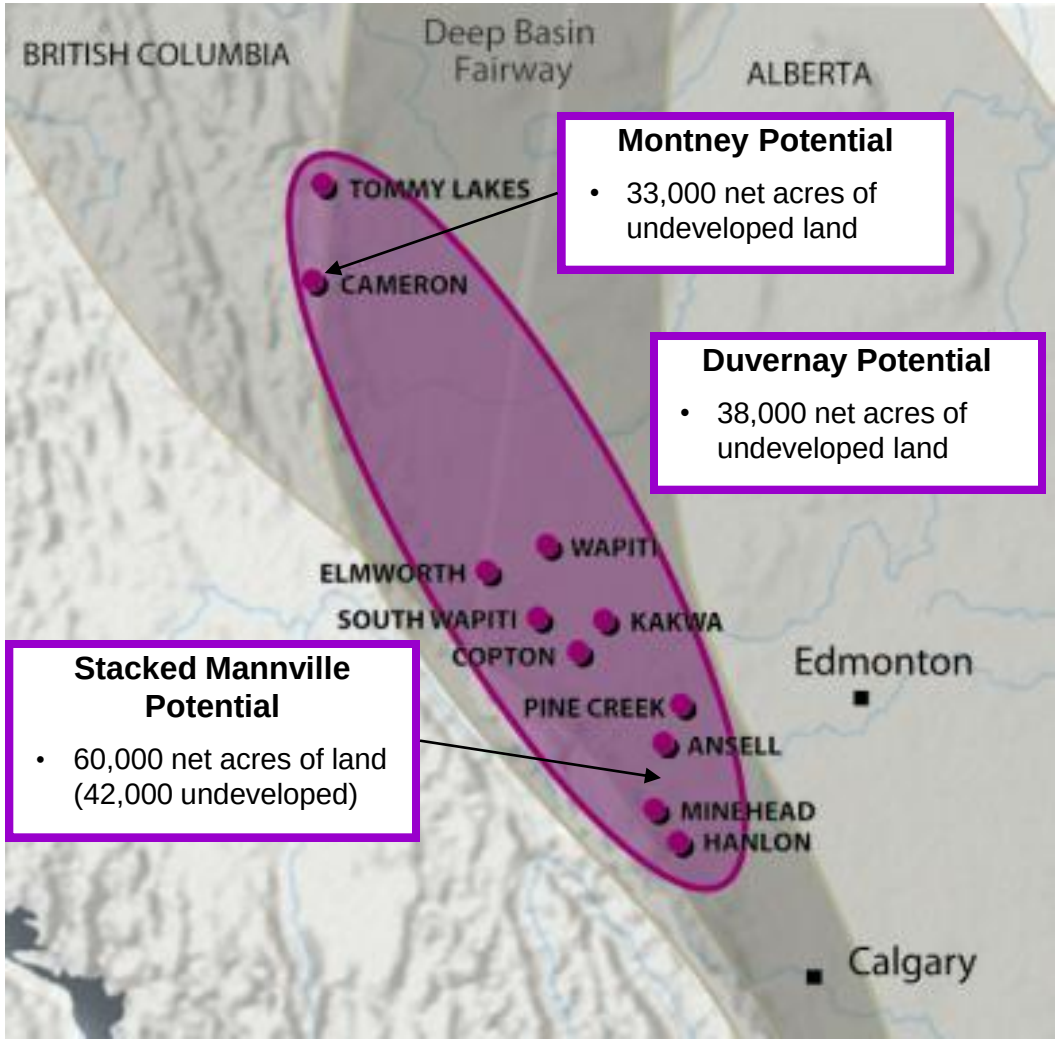
MMcf/d	2011		2012		2013		2014		2015	
	Min	***Max***	***Min***	***Max***	***Min***	***Max***	***Min***	***Max***	***Min***	***Max***
Committed Sales into Transco Pipeline:	12	36	48	74	68	81	65	80	38	45
Committed Sales in to Tennessee Gas Pipeline:	21	30	30	38	14	38	6	6		

  - Participated in the Wyoming Pipeline Project that creates optionality for our production between the two key pipelines - Transco and Tennessee



Supplemental Deep Basin Information

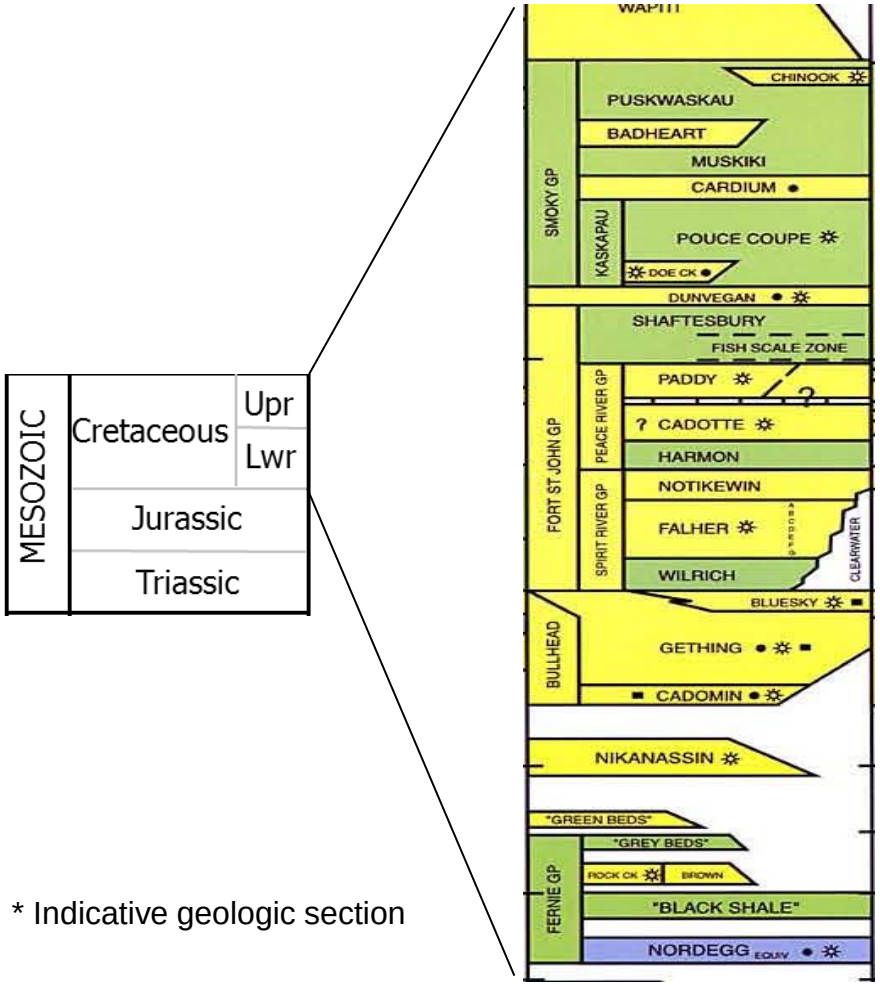
Liquids Rich Natural Gas



Large, long tenure, high working interest land holdings

- Over 110,000 net acres of high working interest undeveloped land with liquids rich gas potential
  - Recently acquired 38,000 net acres in Duvernay Shale
- Multiple contiguous acreage blocks with liquids rich multi-zone potential
- Focused on delineation in 2011 given current gas price environment

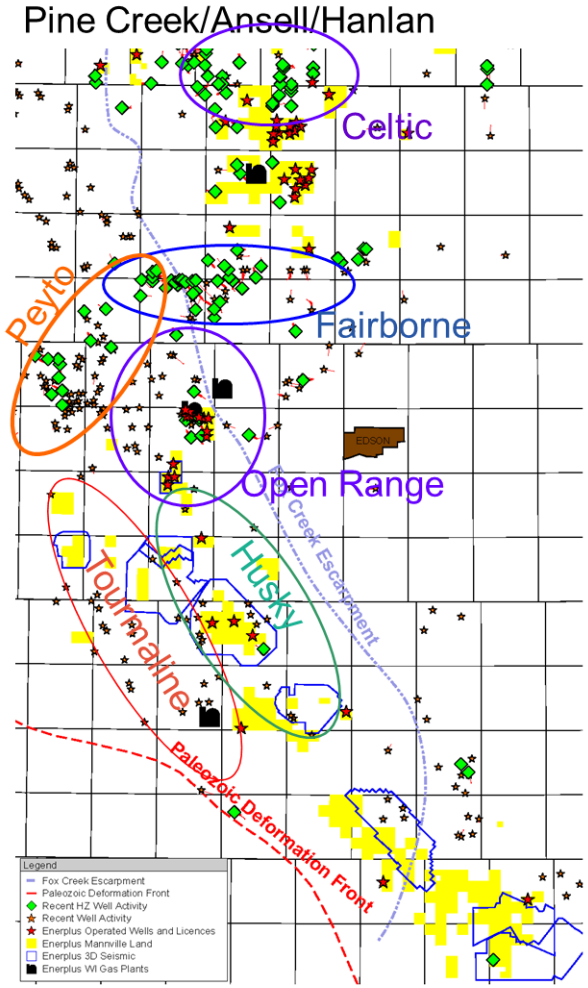
Stacked Mannville Geology



* Indicative geologic section

- Stacked cretaceous horizons provide vertical risk mitigation and multiple horizontal targets
  - Cardium
  - Notikewin
  - Wilrich
  - Bluesky
  - Gething
  - Cadomin

Stacked Mannville



Enerplus working interest lands

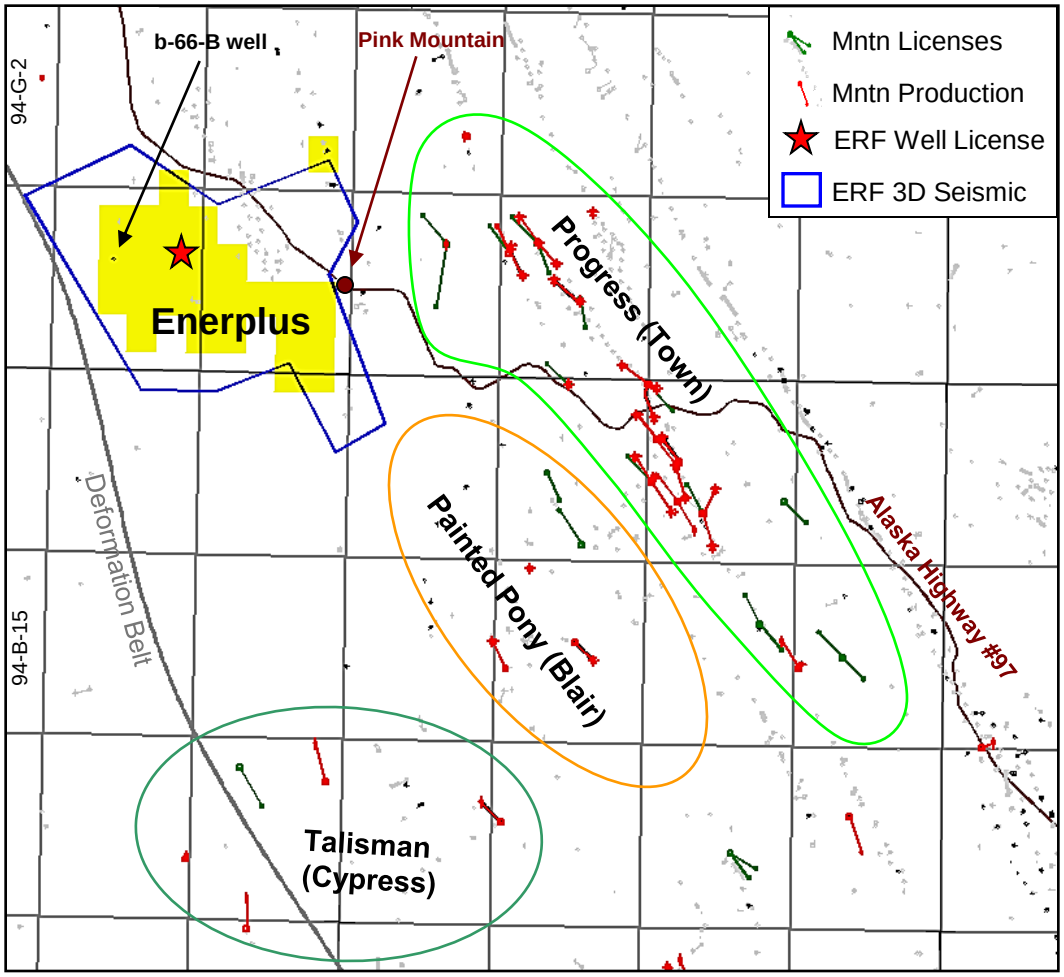
Key Facts	
Key properties	Pine Creek to Hanlan
Net Acreage (acres)	~60,000 total (42,000 undeveloped)
Future HZ Drilling Locations	100 - 200
Expected EUR/Well*	2.8 - 4.0 Bcfe

- Acquiring and utilizing 3D seismic
- Drilled/drilling 3 delineation wells, 3 others licensed and ready to execute in 2011
- Liquids ratios of 15 – 40 bbls/MMcf
- Additional de-risking ongoing by competitors and partners

Contiguous land blocks in highly prospective regions

* Expected EUR/well based on public data from offset wells. Number of future locations based on development of 30% to 60% of Enerplus acreage

Montney



Key Facts	
Key Properties	Cameron / Julienne Creek
Net Acreage (acres)	33,000
Future Hz Drilling Locations	50 – 150
Expected EUR/Well	3.5 – 5.5 Bcfe

- 3D seismic purchased and reprocessed
- Existing well (b-66B) indicates over 300 metres of Montney thickness
- Rock analysis indicates good reservoir development
- Liquids ratio is expected to be between 20 and 30 bbls/MMcf
- Enerplus well licensed in Q1 2011 although drill timing is uncertain

100% working interest

Stacked Mannville Type Curve Economics

Target	Cadomin + 1 up hole completion			Bluesky or Wilrich		
Raw gas recovered	2.8 Bcf Well			4.0 Bcf Well		
AECO ($/Mcf)	IRR%	Payout (Years)	NPV 12% ($MM)	IRR%	Payout (Years)	NPV 12% ($MM)
$6.00	30	2.6	$2.4	74	1.4	$6.2
$5.00	19	3.4	$1.0	53	1.8	$4.6
$4.00	8	5.3	($0.5)	34	2.4	$2.6

Capital	$7.0 million	$6.0 million
30 Day IP	3,700 Mcf/day	3,900 Mcf/day
Liquids	18 bbls/MMcf	15 bbls/MMcf

Type curves are internal estimates based on local analogue/competitor information

Montney Type Curve Economics

	3.5 Bcf Well			4.5 Bcf Well			5.5 Bcf Well		
AECO ($/Mcf)	**IRR %**	**Payout (Years)**	**NPV 12% ($MM)**	**IRR %**	**Payout (Years)**	**NPV 12% ($MM)**	**IRR %**	**Payout (Years)**	**NPV 12% ($MM)**
$6.00	27	2.7	2.1	45	1.8	3.9	64	1.4	5.7
$5.00	18	3.9	0.8	30	2.4	2.4	44	1.8	4.0
$4.00	10	6.5	-0.4	19	3.8	1.0	28	2.6	2.3

Capital	$6.2 million	$6.2 million	$6.2 million
30 Day IP	3,800 Mcf/day	4,000 Mcf/day	4,000 Mcf/day
Liquids	20 bbls/MMcf	20 bbls/MMcf	20 bbls/MMcf
BESC	$4.30/Mcf	$3.37/Mcf	$2.80/Mcf

Type curves are based on Town Montney
Capital assumes pad drilling

Disclaimers

Assumptions

All economics contained have been calculated using forward prices and costs as of February 14, 2011. All amounts are stated in Canadian dollars unless otherwise specified.

Barrels of Oil Equivalent and Cubic Feet of Gas Equivalent

This presentation contains references to "BOE" (barrels of oil equivalent), "Mcfe" (thousand cubic feet of gas equivalent), "Bcfe" (billion cubic feet of gas equivalent) and "Tcfe" (trillion cubic feet of gas equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs, and one barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf) when converting oil to Mcfes, Bcfes and Tcfes. BOEs, Mcfes, Bcfes and Tcfes may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. "MBOE" and "MMBOE" mean "thousand barrels of oil equivalent" and "million barrels of oil equivalent", respectively.

Presentation of Production and Reserves Information

*In accordance with Canadian practice, production volumes and revenues are reported on a "Company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest. Unless otherwise specified, all reserves volumes in this presentation (and all information derived therefrom) are based on "company interest reserves" using forecast prices and costs. "Company interest reserves" consist of "gross reserves" (as defined in National Instrument 51-101 adopted by the Canadian securities regulators ("**NI 51-101**"), being Enerplus' working interest before deduction of any royalties, plus Enerplus' royalty interests in reserves. "Company interest reserves" are not a measure defined in NI 51-101 and do not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our oil and gas reserves statement for the year ended December 31, 2010, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form for the year ended December 31, 2010 ("**our AIF**") which is available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com. Additionally, our Annual Information Form is part of our Form 40-F that has been filed with the U.S. Securities and Exchange Commission and will available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and EDGAR for more complete disclosure on our operations.*

Contingent Resource Estimates

This presentation contain estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage." There is no certainty that we will produce any portion of the volumes currently classified as "contingent resources". The "contingent resource" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2010. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Disclaimers

For information regarding the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with our Marcellus shale gas assets as reserves and the positive and negative factors relevant to the "contingent resource" estimate, see our Annual Information Form for the year ended December 31, 2009 (and corresponding Form 40-F) dated March 12, 2010, a copy of which is available on our SEDAR profile at www.sedar.com and a copy of the Form 40-F which is available on our EDGAR profile at www.sec.gov. With respect to the "contingent resource" estimate for our North Dakota Bakken properties, the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with the properties as "reserves" consist of additional delineation drilling to establish economic productivity in the development areas and limitations to development based on adverse topography or other surface restrictions. Significant positive factors related to the estimate include; continued advancement of drilling and completion technology and early performance of producing wells that are above forecast. A significant negative factor related to the estimate is the limited performance history in the immediate area of the "contingent resource". With respect to our Waterflood assets, the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with the properties as "reserves" are due to the early stage of implementation to the specific patterns within the existing waterfloods and the early stage of the specific enhanced oil recovery projects to the existing waterfloods. Significant positive factors related to the estimate include established waterflood technology, the history of waterflood performance data and the estimates are based on incremental recovery from higher displacement efficiency only with no improved recovery from additional areal sweep. A significant negative factor relevant to this estimate is the geological complexity and its effect on injector producer connectivity. There are a number of inherent risks and contingencies associated with the development of our interests in these properties including commodity price fluctuations, project costs, our ability to make the necessary capital expenditures to develop the properties, reliance on our industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above, and that apply generally to oil and gas operations as described above, and under "Risk Factors" in our Annual Information Form referred to above.

F&D Costs

F&D costs presented are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to its reserves additions for that year.

Non-GAAP Measures

*In these presentations, we use the terms "payout ratio" and "adjusted payout ratio" to analyze operating performance, leverage and liquidity, and the term "F&D costs" as a measure of operating performance. We calculate "payout ratio" by dividing cash distributions to unitholders by cash flow from operating activities, both of which are measures prescribed by Canadian generally accepted accounting principles ("**GAAP**") and which appear on our consolidated statements of cash flow. "Adjusted payout ratio" is calculated as cash distributions to unitholders plus development capital and office expenditures, divided by cash flow from operating activities. We also use the term "netback", which is used to measure operating performance and is calculated by subtracting Enerplus' expected royalties and operating costs from the anticipated revenues in respect of the relevant properties. Enerplus believes that, in addition to net earnings and other measures prescribed by GAAP, the terms "payout ratio", "adjusted payout ratio", "F&D costs" and "netback" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by GAAP and do not have a standardized meaning prescribed by GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers.*

Disclaimers

NOTICE TO U.S. READERS

*The oil and natural gas reserves information contained herein has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. Reserves categories such as "proved reserves" and "probable reserves" may be defined differently under Canadian requirements than the definitions contained in the United States Securities and Exchange Commission (the "**SEC**") rules. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Canadian disclosure requirements require that forecasted commodity prices be used for reserves evaluations, while the SEC mandates the use of an average of first day of the month price for the 12 months prior to the end of the reporting period. Additionally, the SEC prohibits disclosure of oil and gas resources, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "Information Regarding Reserves, Resources and Operational Information" above.*

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This presentation contains certain forward-looking information and statements ("**forward-looking information**") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, these presentations contains forward-looking information pertaining to the following: Enerplus' strategy to deliver both income and growth to investors and Enerplus' related asset portfolio; future returns to shareholders from both dividends and from growth in per share production and reserves; future capital and development expenditures and the allocation thereof among our resource plays and assets; future development and drilling locations and plans; the performance of and future results from Enerplus' assets and operations, including anticipated production levels and decline rates; future growth prospects, acquisitions and dispositions; the volumes and estimated value of Enerplus' oil and gas reserves and contingent resource volumes and future commodity price and foreign exchange rate assumptions related thereto; the life of Enerplus' reserves; the volume and product mix of Enerplus' oil and gas production; securing necessary infrastructure and third party services; the amount of future asset retirement obligations; future cash flows and debt-to-cash flow levels; potential asset sales; returns on Enerplus' capital program; Enerplus' tax position; and future costs, expenses and royalty rates.*

The forward-looking information contained in this presentation reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of Enerplus' reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund Enerplus' capital and operating requirements as needed; and the extent of its liabilities. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

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