Investor Update

November 2010

enerPLUS

Advisory

- 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, this presentation contains forward-looking information pertaining to the following: Enerplus' strategy; the performance of Enerplus' assets and operations; future growth prospects, acquisitions and dispositions; future cash distributions and dividends to securityholders; capital and development expenditures and the timing and allocation thereof; the volumes and estimated value of the Fund's oil and gas reserves and contingent resource volumes; the life of the Fund's reserves; the volume and product mix of the Fund's oil and gas production; future results from operations; future development and drilling locations and plans; the installation of infrastructure; receipt of regulatory approvals; commodity prices and foreign exchange rates; the amount of future asset retirement obligations; returns on the Fund's capital program; the conversion from an income trust to a corporation and the timing thereof; Enerplus' tax position; and future costs, expenses and royalty rates.
- The forward-looking information contained in this presentation reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; the accuracy of the estimates of the Fund's reserve and resource volumes; certain commodity price and other cost assumptions; the continued availability of adequate debt and/or equity financing and cash flow to fund its capital and operating requirements as needed; and the extent of its liabilities. The Fund 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.
- The forward-looking information included in this presentation are not guarantees of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in the demand for or supply of the Fund's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans the Fund or by third party operators of the Fund's properties, increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in the Fund's public disclosure documents (including, without limitation, those risks identified in the Fund's Annual Information Form and Form 40-F described above).
- All financial figures are in Canadian dollars unless otherwise stated.
- Enerplus’ financial statements are prepared in accordance with Canadian generally accepted accounting principles (“GAAP”). Canadian GAAP differs in some significant respects from U.S. GAAP and therefore this financial information may not be directly comparable to the financial information typically provided by U.S. companies. The principal differences as they may apply to Enerplus are summarized in Note 14 to the Fund’s audited consolidated financial statements for the year ended December 31, 2009. A complete copy of the audited financial statements and notes is available without charge from Enerplus.
- Our payout ratio is calculated as cash distributions divided by cash flow from operating activities. The term payout ratio does not have a standardized meaning as prescribed by GAAP and therefore may not be comparable with the calculation of a similar measure by other entities. This reflects the proportion of cash flow paid out to investors and not reinvested in the business.
- This presentation contains references to "Mcfe" (thousand cubic feet of gas equivalent), “MMcfe” (million 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 one barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf) when converting oil to Mcfe, MMcfe, Bcfe or Tcfe. Mcfes, MMcfes, Bcfes and Tcfes may be misleading, particularly if used in isolation. A conversion ratio of 1 bbl: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Advisory

- 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, MMcfes, Bcfes and Tcfes. BOEs, Mcfes, MMcfes, 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.

- Unless otherwise stated, all production volumes are stated on a gross basis, that is, our working interest production before the deduction of any royalty interest production.

- 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") 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, 2009, 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, 2009 ("our AIF") which will be available on or about March 12, 2010 on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com. Additionally, the Annual Information Form will form part of our Form 40-F that will be filed with the U.S. Securities and Exchange Commission and will be 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 concurrently with this presentation for more complete disclosure on our operations.

- This presentation contains 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 Enerplus will produce any portion of the volumes currently classified as contingent resources or that Enerplus 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, 2009. 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.

- For information regarding the primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with its Marcellus shale gas and Fort Berthold assets as reserves and the positive and negative factors relevant to the contingent resource estimate, see the Fund's material change report dated August 27, 2009, copies of which are available on SEDAR and EDGAR as described above.
- For additional information with respect to the presentation and disclosure of oil and gas reserves and resources, see "Presentation of Enerplus' Oil and Gas Reserves, Resources and Production" in the AIF.

Enerplus Strategy

- High yielding North American oil and gas producer
- Long-term, profitable growth potential from key resource plays with superior economics in various commodity price cycles - Marcellus shale gas and Bakken crude oil
- Repositioning mature asset base to improve focus and profitability
- Cash flow from mature base utilized to support both investment into growth plays and dividend
- Balance sheet strength will support investment into new assets and continued acquisitions

Total return target of 10-15% is achievable with our current asset base:

5% growth +/-

5 - 10% yield +/-

Corporate Conversion

- Unitholder meeting scheduled for December 9, 2010 and expect to convert to a dividend paying corporation effective January 1, 2011
- Expect to maintain distributions at $0.18/unit/month through conversion
- Straight-forward conversion – one trust unit for one common share
- Tax-deferred exchange for all unitholders
- Will continue to pay monthly dividend post conversion
- No change to name or ticker symbols (elimination of .un on TSX)
- No acceleration or vesting of any compensation awards to employees or Directors

Conversion not expected to impact our cash flow for 3 – 5 years

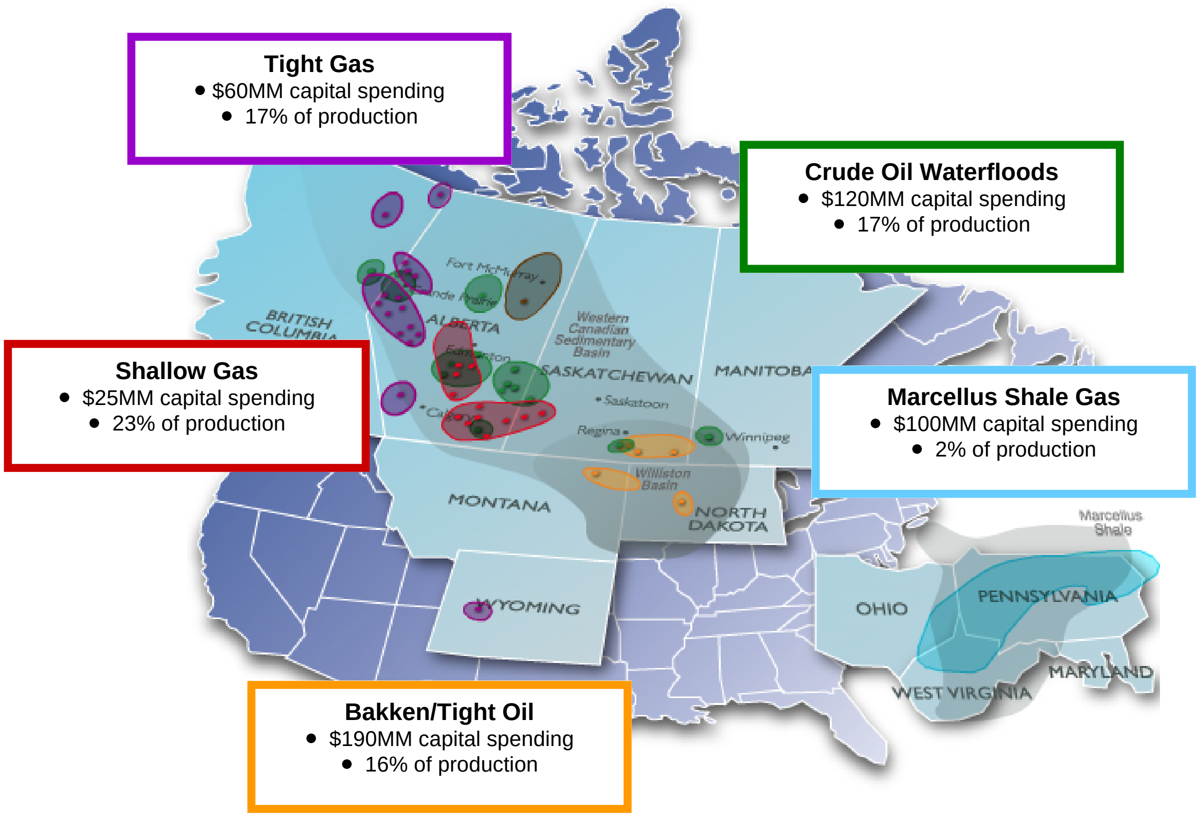
Transitioning the Portfolio

Over 475,000 net new acres of undeveloped land added

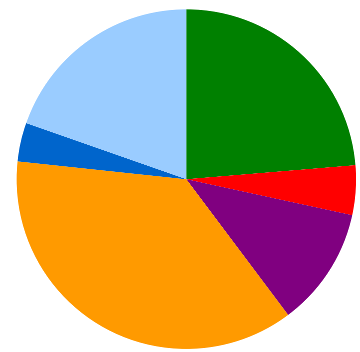
Over 10,000 BOE/day of non-core conventional production sold

- Acquiring new growth assets that have superior economics and ability to add meaningful production and reserves
  - Marcellus Shale Gas: ~200,000 net acres in PA, WV and Maryland
  - Bakken Crude Oil: +210,000 net acres in ND and SK
- Improving the profitability of our business through greater focus on fewer high impact properties
  - Reduced number of properties in portfolio by 40%
  - Expect 5 - 10% reduction in operating costs
- Disposition proceeds have funded majority of new growth and preserved financial strength

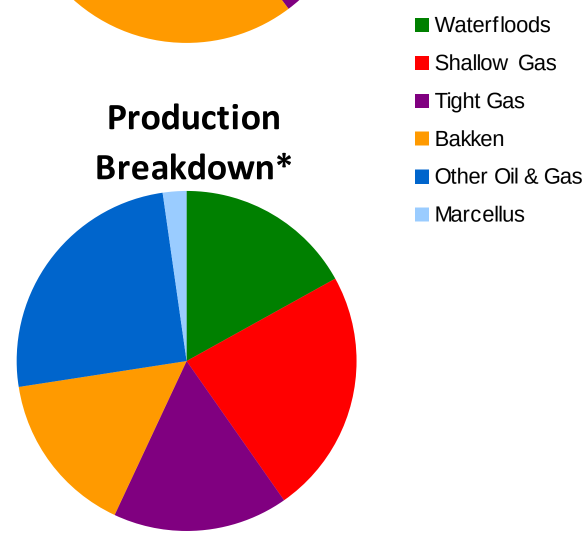
Our Assets



Capital Spending*



Production Breakdown*



* Production is Q3 2010 daily average, capital is 2010 expected spending

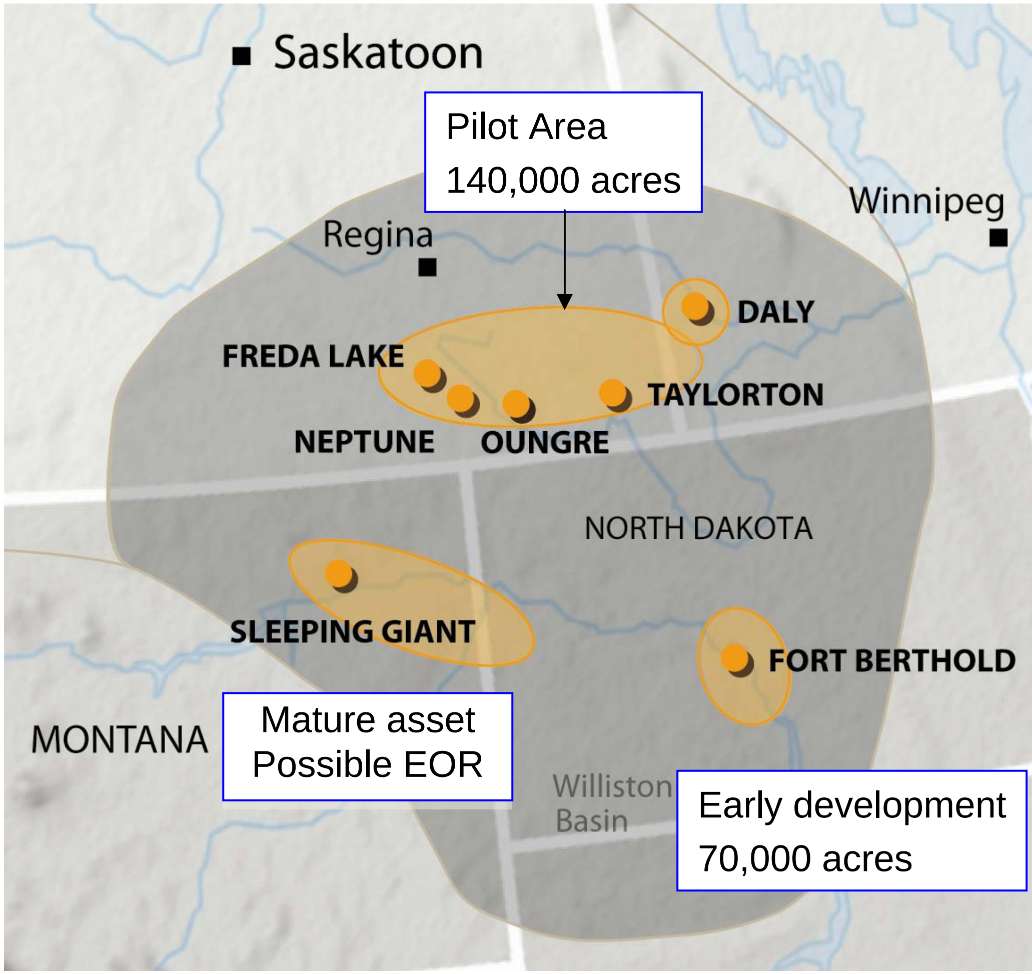
2010 Year to Date Operating Performance

	Cal 2010 Guidance*	YTD 2010
Annual Average Production (MBOE/day)	83 – 84	84.2
Natural Gas	58%	58%
Exit Rate Production (MBOE/day)	80 – 82	N/A
Natural Gas	55%	
Capital Spending ($MM)	$515	$314
Operating Costs ($/BOE)	$10.20	$10.02
Distributions Paid ($MM)	-	$288
Annual Adjusted Payout Ratio	137%	108%
Debt/Cash Flow Ratio at Year-End	1.3x	0.9x

*adjusted for divestments

- Production volumes on track with expectations, post divestment activity
- Sold 6,000 BOE/day YTD
- Operating costs declining
- 60% of capital spending on oil projects
- Significant production increases in Bakken and Marcellus

Bakken/Tight Oil Portfolio



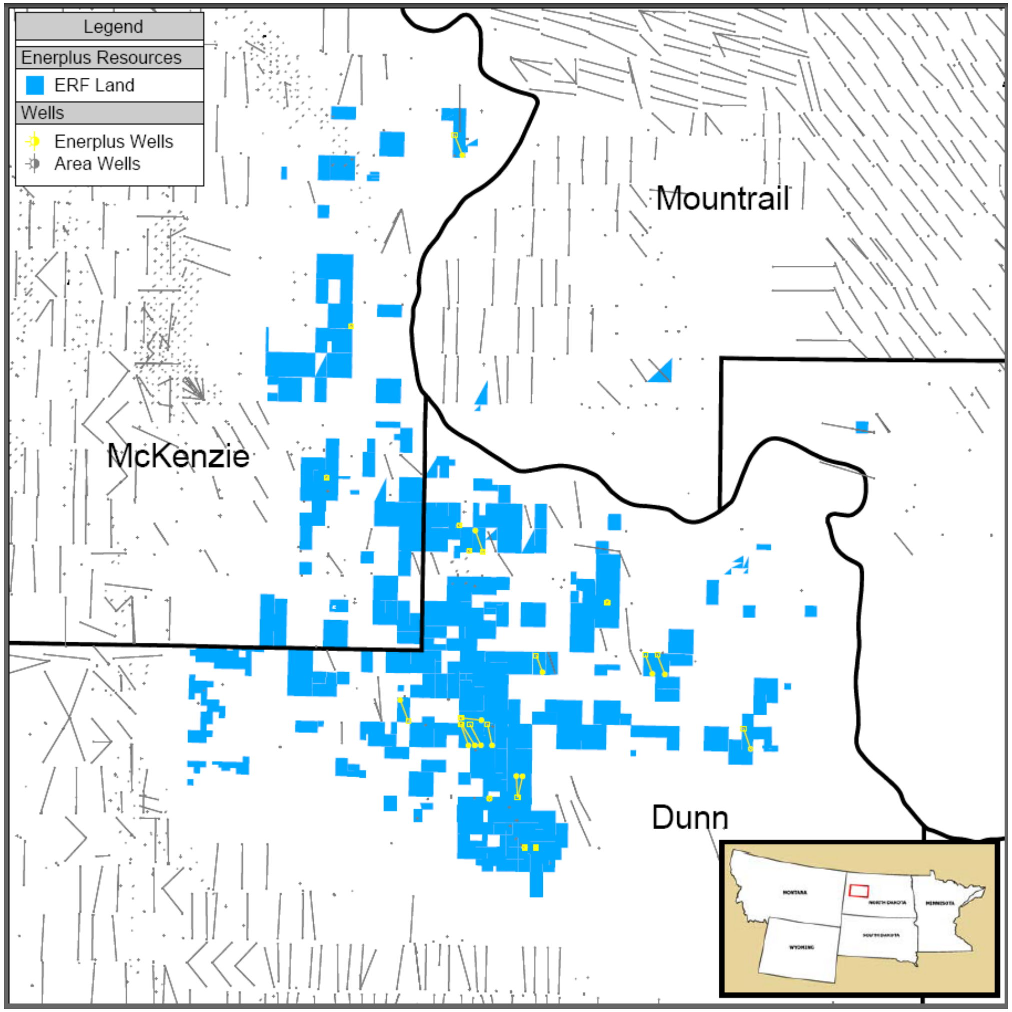
Key Facts	
Net Acreage	**215,000**
Current Production	**13,000 BOE/day**
2009 P+P Reserves	**42 million barrels**

- High quality, light oil potential from the Bakken and Three Forks formations
- Superior economics and netbacks
- Significant reserve and production growth potential
- Three key focus areas:
  - Fort Berthold, North Dakota
  - Freda Lake/Neptune/Oungre, SK
  - Sleeping Giant, Montana

Bakken/Three Forks Growth Potential

Area	OOIP/ Section	Depth (ft)	Est. Recovery/ Section	EUR per Well	Wells per Section	Net Undeveloped Acreage	# of Future Locations
Fort Berthold, ND (Bakken)	4 to 6 MMBOE	11,000	12-16%	Short - 300 to 400 Mbbls Long - 600 to 800 Mbbls	2 short/ 640 acres 2 long/1280 acres	112 sections	130-150
Fort Berthold, ND (Three Forks)	4 to 5 MMBOE	11,000	10-14%	Short - 250 to 300 Mbbls Long - 500 to 600 Mbbls	2 short/640 acres 2 long/1280 acres	112 sections	Under evaluation
Freda Lake, Neptune, Oungre, Taylorton, SK (Bakken)	3 to 4 MMBOE	6,500	10-15%	100-150 Mbbls	4	222 sections	Under Evaluation

Fort Berthold Lease Area



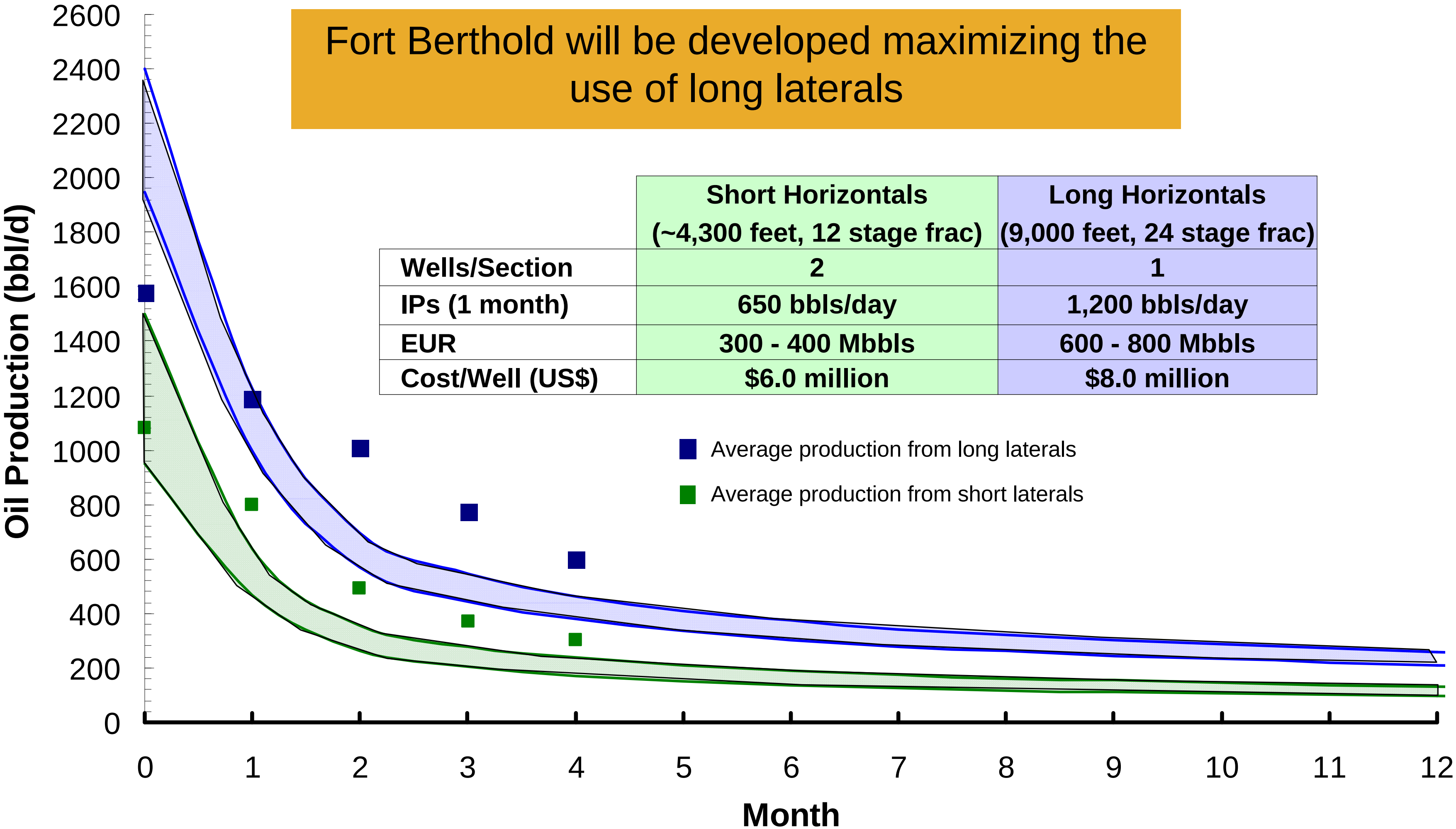
Key Facts	
Net Acreage	**74,500**
Current Production	**~4,000 BOE/day**
Internal Bakken Reserve Est.	**18 million BOE**
Internal Bakken Contingent Resource Est. (Best)	**50 million BOE**

- Primarily operated with over 90% working interest
- 85% of land is prospective
- Average lease tenure of 7.5 years
- Upside from Three Forks
- Production expected to grow to 20,000+ BOE/day in 5 years

Ft. Berthold Type Well

Fort Berthold will be developed maximizing the use of long laterals

	Short Horizontals (~4,300 feet, 12 stage frac)	Long Horizontals (9,000 feet, 24 stage frac)
Wells/Section	**2**	**1**
IPs (1 month)	**650 bbls/day**	**1,200 bbls/day**
EUR	**300 - 400 Mbbls**	**600 - 800 Mbbls**
Cost/Well (US$)	**$6.0 million**	**$8.0 million**



Fort Berthold Results

Wells	30 Day Average Production/Well*	60 Day Average Production/Well*
4 Short Laterals	800 bbls/day	650 bbls/day
2 Long Laterals	1,190 bbls/day	1,110 bbls/day

100 day cumulative production from our 2 long laterals totaled 101,000 and 91,000 bbls respectively

* Production rates do not include associated natural gas
* Production from long laterals has been limited due to fluid handling capacity

Marcellus Overview

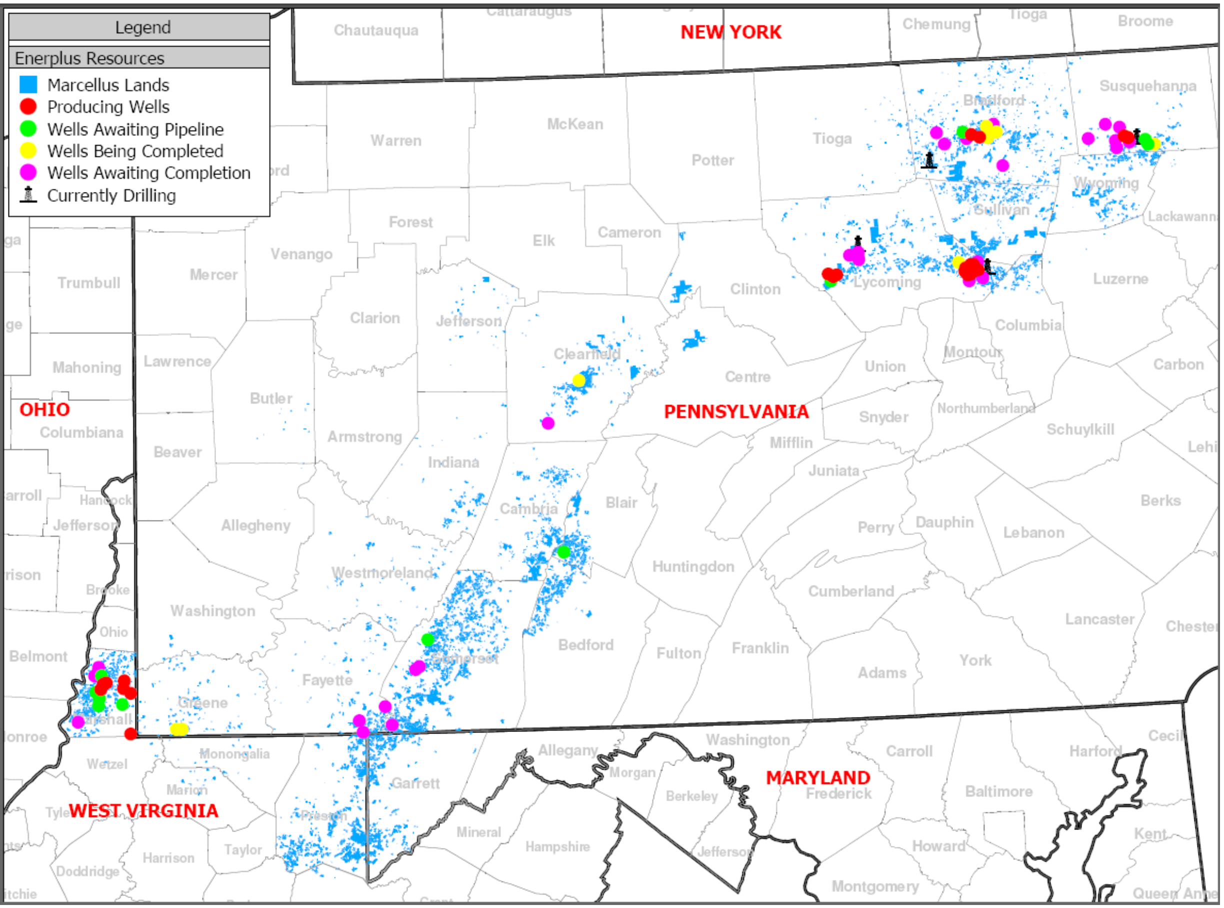
Production growth of over 150 MMcf/day over next 4 yrs

Over 2.4 Tcfe of natural gas potential*

- Entry into one of the most economic and largest shale gas plays in North America
- ~ 200,000 net acres
  - 70,000 net operated acres with an average working interest of 90%
  - Average 23% non-operated working interest in approximately 565,000 gross acres (approximately 128,500 net acres) primarily in Pennsylvania and West Virginia with Chief Oil & Gas
- Non-operated Marcellus position alone has the potential to triple our proved plus probable natural gas reserves

*excluding operated land in W. Virginia & Maryland

Land Position



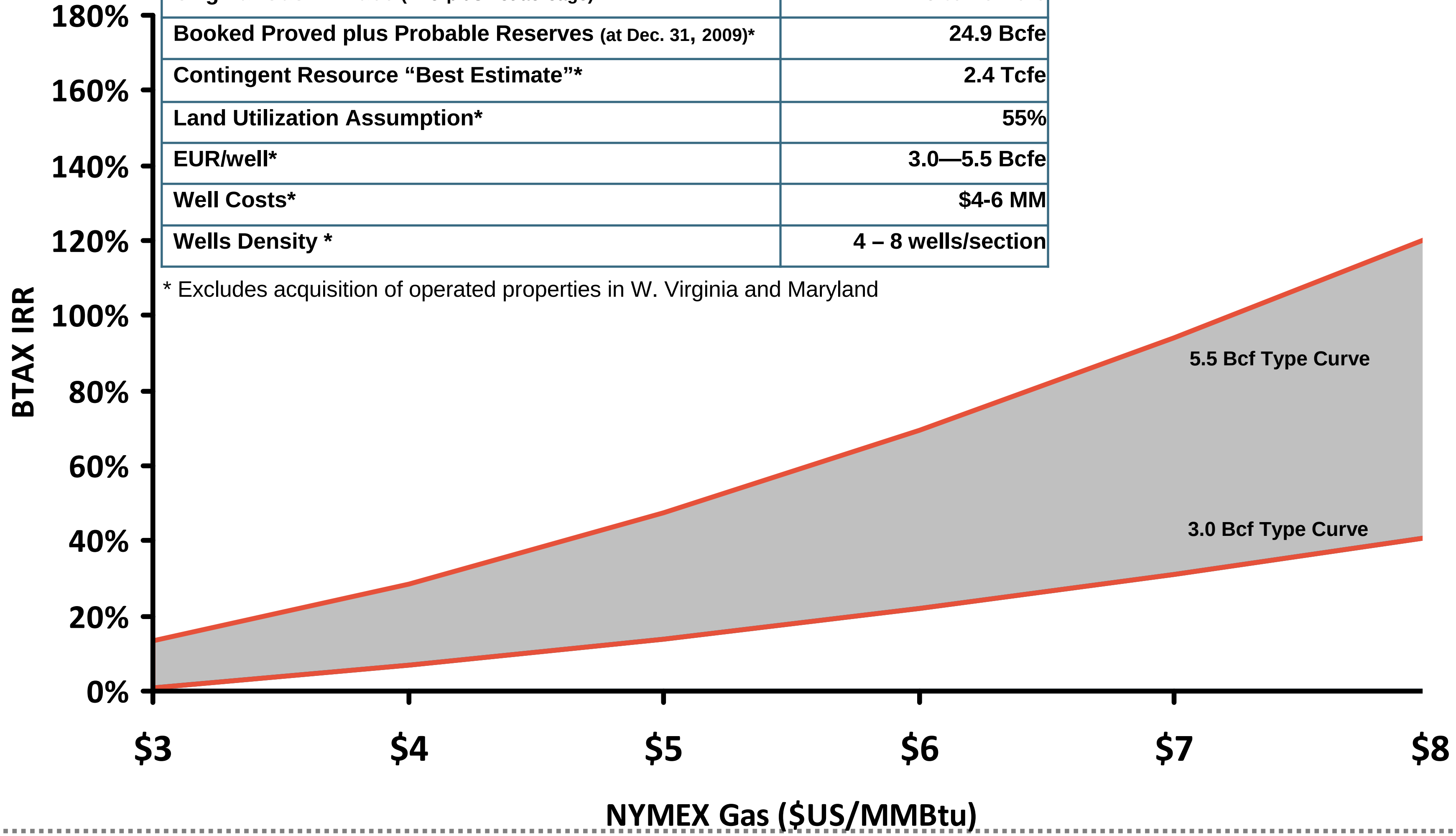
Key Metrics	
Net Operated Acres	70,000
Net Non-Operated Acres	128,500
Est. Full Cycle FD&A	$1.60/Mcf
Best Estimate Contingent Resources	2.4 Tcf

- Production has increased from 2 MMcf/day to 16 MMcf/day year-to-date
- Over 1,000 net future drilling locations
- Drilling first operated well in Clinton County, PA
- No significant lease expiries anticipated based upon current development plans

Potential in the Marcellus

Original Gas in Place (Enerplus net acreage)*	13 to 15 Tcfe
Booked Proved plus Probable Reserves (at Dec. 31, 2009)*	24.9 Bcfe
Contingent Resource "Best Estimate"*	2.4 Tcfe
Land Utilization Assumption*	55%
EUR/well*	3.0—5.5 Bcfe
Well Costs*	$4-6 MM
Wells Density *	4 – 8 wells/section

* Excludes acquisition of operated properties in W. Virginia and Maryland

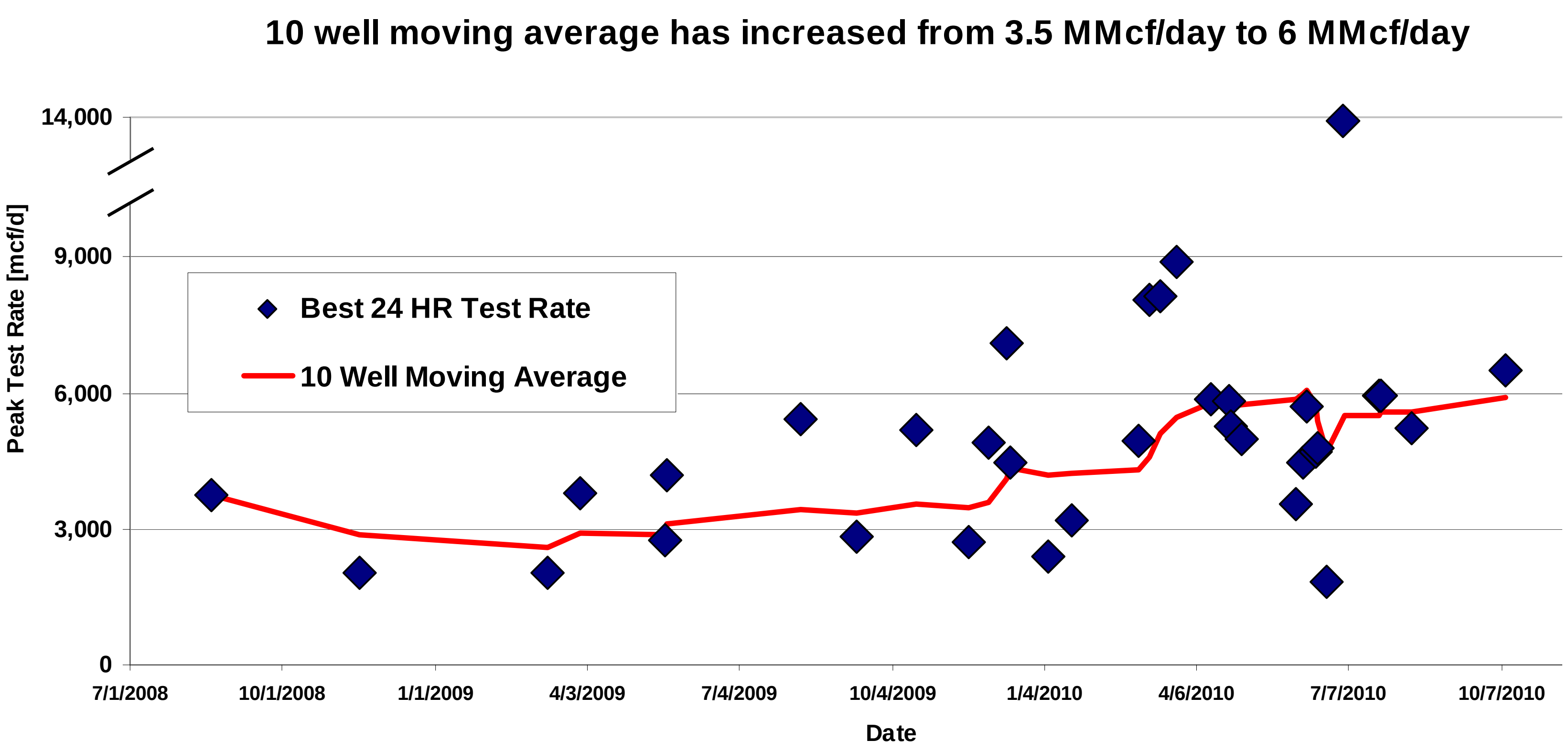


Marcellus Drilling Activity

Gross Wells Drilled (at Nov 1, 2010)	**Horizontal**	**Vertical**	**Total**
Producing	36	6	42
Waiting on Completion	29	7	36
Waiting on Pipeline	9	6	15
Total Gross Wells	**74**	**19**	**93**

- Drilling activity in 9 counties in PA as well as Marshall county in West Virginia
- Majority of producing wells in Bradford, Lycoming and Susquehanna Counties in PA (>80% of current production) and Marshall County in WV
- Best 24-hour test rate of 14 MMcf/day in SW Pennsylvania
- 20 wells being drilled or remain to be drilled in 2010
- 9 rigs currently running

Rate Improvement Over Time



Executing on our Strategy

- Enerplus is well positioned in our transition toward a growth and income business
- Significant progress has been made in acquiring early stage resource plays
  - ~475,000 net acres of prospective undeveloped land in the Marcellus, Bakken/tight oil and Deep Basin tight gas plays
- Divestment plans have focused our asset base on key resource plays and funded acquisitions in 2010
- Strong balance sheet will support organic growth opportunities and further acquisition activity
- Current focus on executing development programs

Supplemental Information

November 2010

enerPLUS

Corporate Profile

• Trading Symbols (TSX/NYSE)	ERF.un/ERF
• Market Capitalization (1)	$5.2 billion
• Enterprise Value (2)	$5.9 billion
• Average Daily Trading Value (Oct 2010)	$28 million
• Average Daily Production	82,869 BOE/day
– Gas Weighting	57%
• Q3 Long-Term Debt /Trailing 12-Month Cash Flow Ratio (3)	0.9x
• Current Monthly Cash Distribution	$0.18/unit
• Current Annualized Yield	7.4%

(1) Market Cap. at November 11, 2010 – based upon 178,118,000 units outstanding at September 30, 201
(2) Market Cap. at November 11, 2010 plus outstanding debt *(net of cash)* at September 30, 2010
(3) Using outstanding debt and Cash Flow from Operations at September 30, 2010

Why Dividends?

- Imposes capital discipline and sensible pace of development (especially for early stage growth assets)
- Demand for yield supported by demographics, Enerplus’ current investor base, and low interest rate environment
- Asset portfolio supports the model
- Mature properties with <20% decline generate consistent cash flow
- Dividend paying stocks have historically outperformed and earned a premium valuation

We will continue to share a significant portion of our cash flow with investors

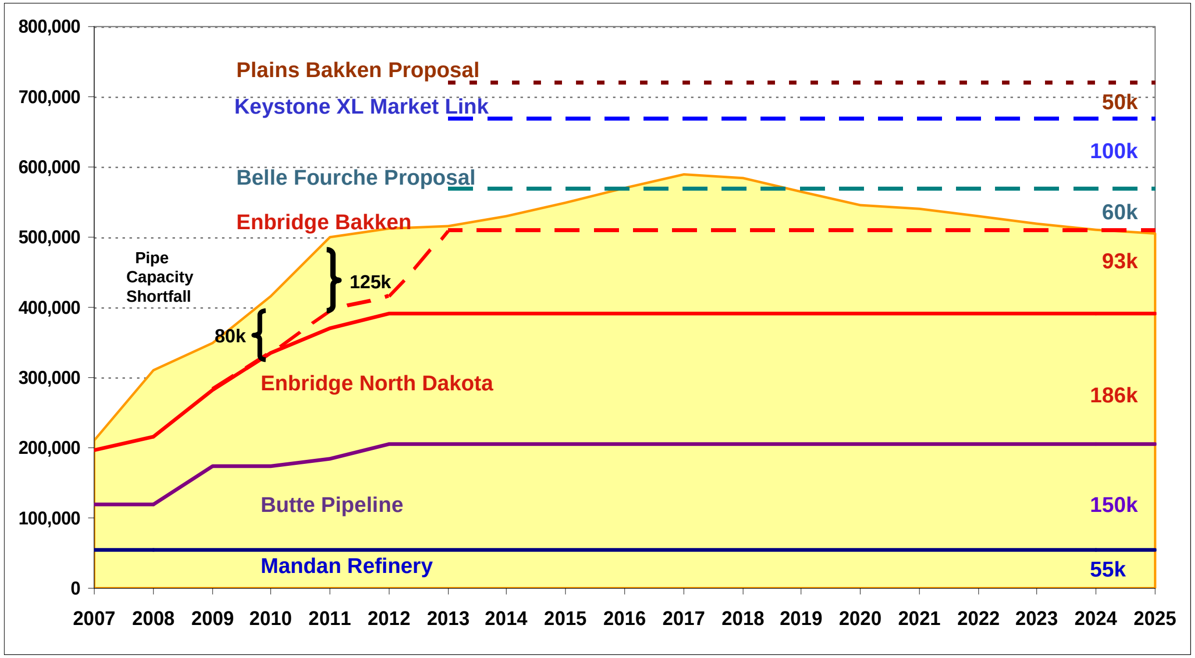
Progress on Portfolio Transition

Acquisitions	Net Acreage	Cost ($ Million)
Marcellus Non-Operated Acreage	128,500 acres	$448
Marcellus Operated Acreage	70,200 acres	$185
North Dakota Bakken	74,500 acres	$618
Saskatchewan Bakken	140,000 acres	$176
Deep Basin	65,000 acres	$40
Total	478,200 acres	$1,467

Dispositions	Production	Proceeds ($ Million)
Non-Core Conventional Assets(1)	~10,500 BOE/day	~$600
Kirby Oil Sands	-	$405
Total Proceeds		~$1,005

(1) Acquisition and disposition activity in cal 2009 and YTD 2010 including 4,500 BOE/day from third non-core asset sale that has not yet closed

US Bakken Infrastructure Capacity

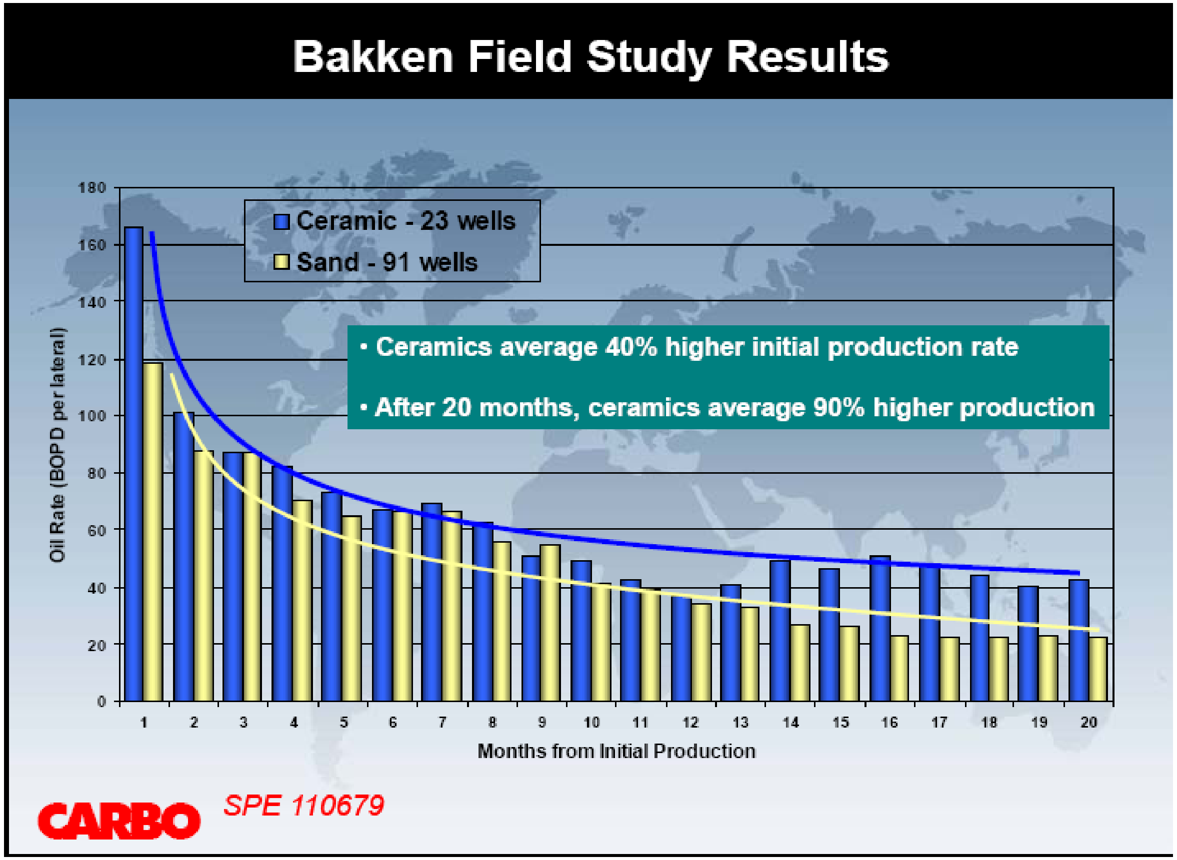


- Source: Internal company data and industry analysis

- Current US Bakken production is ~400 MBOE/day
  - 500 MBOE/day in 2011
- Pipeline capacity shortfall:
  - 80 MBOE/day in 2010
  - could increase to 125 MBOE/day in 2011
  - Rail and trucking covers capacity shortfall

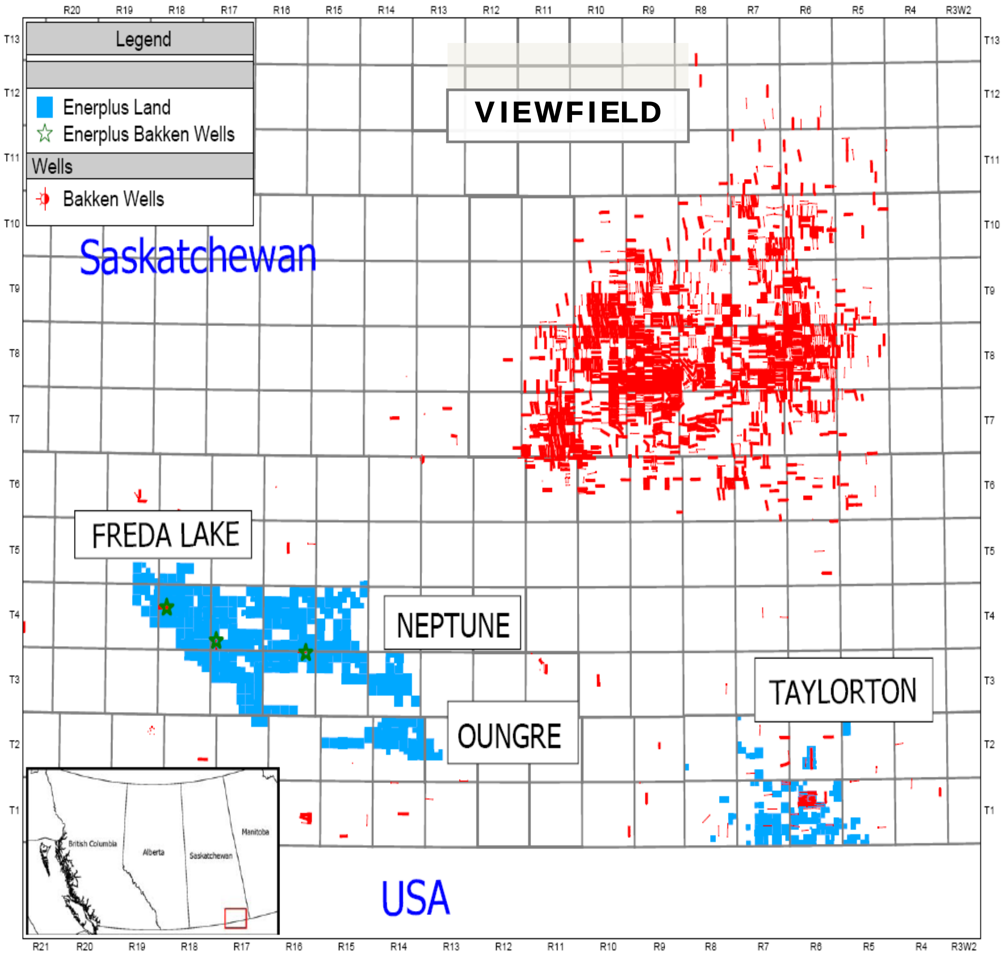
- Numerous new pipelines and expansions of over 300 MBOE/day are proposed to address the takeaway shortfall
- We control some pipeline capacity and also sell to intermediaries who hold capacity on existing pipelines or who have access to trucking/railing facilities
- Evaluating securing additional pipeline capacity to address production growth

Proppant Crushing



- White sand will crush at depths > 6000 ft, significantly reducing fracture conductivity
- Higher strength proppants (HSP) or ceramics are required as stress increases.
- Recent wells completed with HSP exhibit higher IP's and shallower early production declines
- Incremental cost of ~$1 - $1.5 million/well

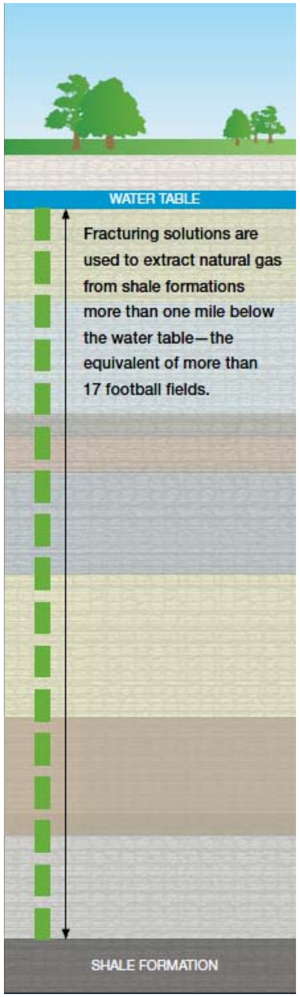
Canadian Bakken



Key Facts	
Net Acreage	**140,000**
Wells Drilled	**9**
Reserves Booked	**0**

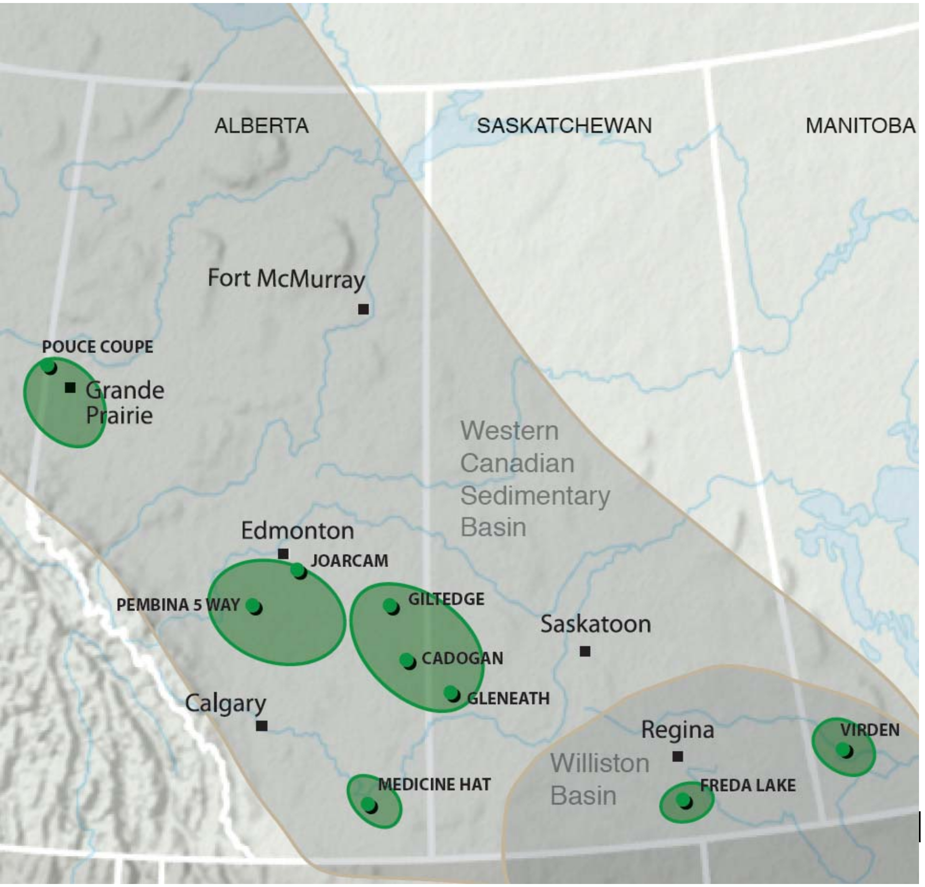
- Freda Lake/Neptune/Oungre
- Delineation drilling and seismic shoot underway
- Currently evaluating - mixed results to date

Marcellus Environmental Concerns



- Freshwater aquifers range in depth from 80 to 500 feet below surface
- Drilling depth in the Marcellus ranges from 4,500 feet to over 7,500 feet across the play
- Drilling and completion techniques are designed to minimize contamination risks:
  - Surface casing set and cemented to approximately 900 feet below surface
  - Intermediate casing set and cemented to 2,400 feet below surface
- Surface containment system being used
  - Poly liner covering well site
  - Isolates spills from fracture process
  - Flowback/water storage pits double lined with 2 layers of 40 ml. plastic liner
  - Greatly reduces off-pad migration potential

Crude Oil Waterfloods Overview



Key Facts	
# of Major Prospects	8
P+P Reserves (2009)	95.9 million barrels
Q3 2010 Production	~14,000 BOE/day
2010 Capital Budget	~$120 million

- Mature, cash generating assets with low base decline that fit income model
- 2010 capital program will maintain production yr over yr excluding divestments
- Horizontal drilling application improving recoveries
- Advancing work on EOR at most prospective fields

Crude Oil Waterfloods Capital Program – Major Properties

2010 capital program should maintain production

Prospect	2010 Capital Budget	Net Wells	Comments
Freda Ratcliffe	$32 million	9 hz	increasing production and handling capacity
Medicine Hat	$20 million	6 hz	waterflood optimization, debottlenecking and increasing facilities capacity
Giltedge	$20 million	10 vertical	waterflood optimization, facilities work, and commencing first polymer flood pilot
Virden	$14 million	4 hz	4 net horizontal Lodgepole wells and significant facilities upgrades
Gleneath	$8 million	6 hz	Determining Viking potential

Hedging Strategy

- Protect a portion of cash flow to support capital spending, economics of our acquisitions and income distribution
- Provide downside protection and retain upside price increases
- Typically hedging forward 2 years
- Combination of instruments utilized - puts, calls, swaps
- Not hedging in current natural gas price environment

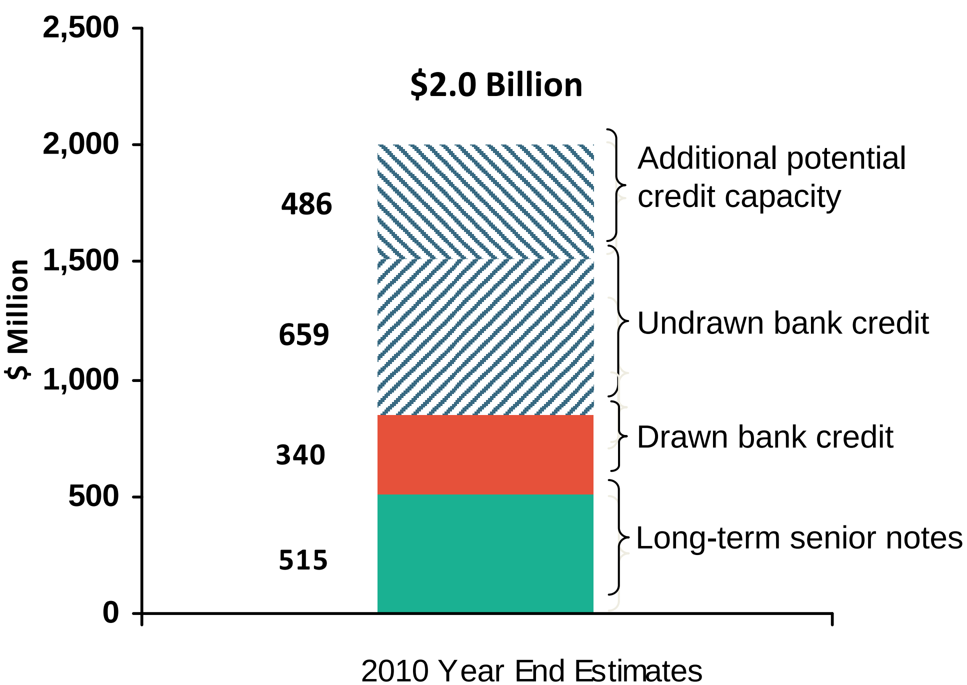
2011 Hedge Positions:

39% of crude oil production hedged at US$86.18/bbl

42% of natural gas production hedged at effective price of $6.10/Mcf through March 2011

Balance Sheet Strength

Debt-to-cash flow ratio estimated at 1.3x by year end



- After adjusting for recent acquisition and divestment activities Enerplus expects year end long-term debt of ~$855 million
  - ~$340 million in bank debt
  - ~$515 million in senior notes
- Enerplus' senior notes are rated NAIC2.
- Asset base would support a larger credit facility however we chose to reduce the size due to increase in cost of maintaining unused credit capacity
- Maximum debt restriction of 3x EBITDA could support $2.0 billion in credit with over $1.1 billion in available capacity expected at year end

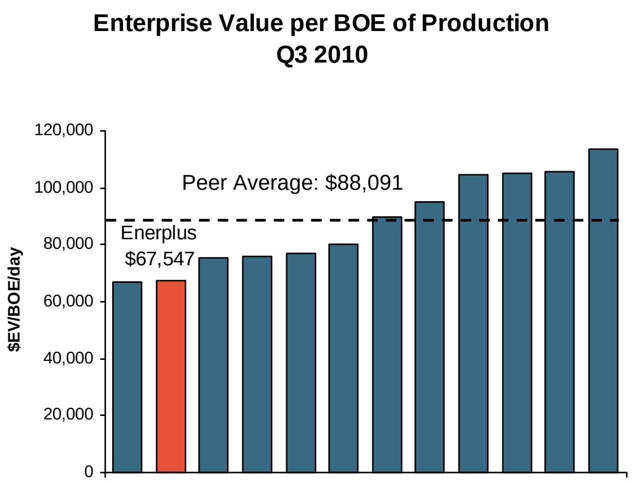
$1 Billion Credit Facility

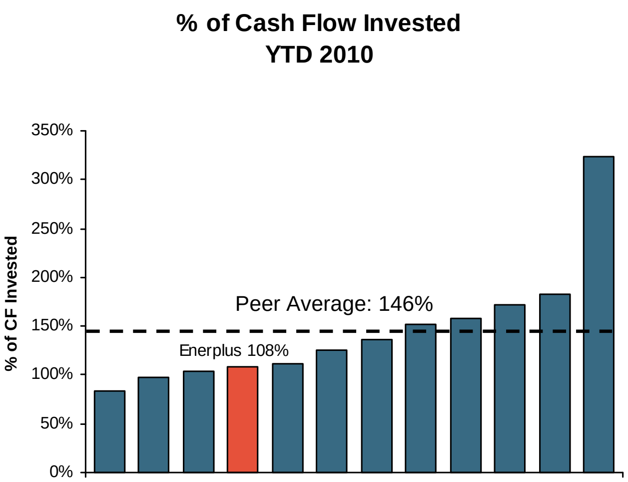
Canadian Imperial Bank of Commerce	$145
Royal Bank of Canada	$120
Bank of Montreal	$120
Bank of Nova Scotia	$110
Toronto Dominion Bank	$100
National Bank of Canada	$85
Alberta Treasury Branches	$50
Total Canadian	**$730**
HSBC Bank	$85
Citibank N.A.	$85
Union Bank of California	$50
Sumitomo Mitsui Bank	$50
Total Foreign	**$270**

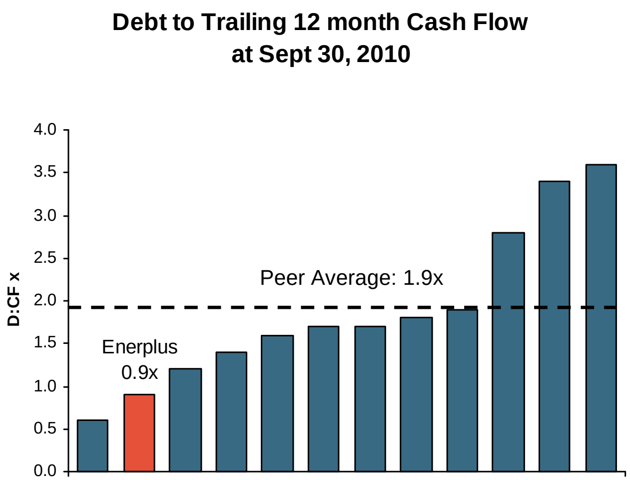
Analyst Coverage

Research Firm	Analyst	Rating
Bank of America	Andrew Fairbanks	Sell
BMO Capital Markets	Gordon Tait	Hold
CIBC World Markets	Jeremy Kaliel	Hold
Canaccord Capital	Kyle Preston	Buy
Citigroup	Richard Roy	Buy
Dundee Securities Corp.	Travis Wood	Hold
FirstEnergy Capital Corp.	Jill Angevine	Buy
Macquarie Capital Markets	Cristina Lopez	Hold
National Bank Financial	Menal Patel	Hold
Peters & Co. Limited	Kam Sandhar	Hold
Raymond James	Kristopher Zack	Buy
RBC Dominion Securities	Fergal Kelly	Hold
Scotia Captial	Patrick Bryden	Sell
TD Newcrest	Roger Serin	Buy
UBS	Matt Donohue	Hold

Attractive Valuation







Peer group includes ARC Resources, Baytex, Bonavista, Cabot, EXCO, Pengrowth, Pennwest, Petrohawk, Range, Ultra, Vermilion

Investor Relations Contacts

Jo-Anne M. Caza
Vice President, Corporate & Investor Relations
403-298-2273
jcaza@enerplus.com

Garth Doll
Manager, Investor Relations
403-298-1218
gdoll@enerplus.com

1-800-319-6462
investorrelations@enerplus.com

www.enerplus.com

The Dome Tower
Suite 3000, 333 7th Ave SW
Calgary, AB Canada
T2P 2Z1

ERF.UN LISTED TORONTO stock EXCHANGE TSX

ERF LISTED NYSE®