CORPORATE PRESENTATION

ENCANA CORPORATION

July 2015

encana®

2015 FOCUS

Navigating Market Volatility From a Position of Strength

Executing a disciplined capital program	• ~80% of capital to Permian, Eagle Ford, Duvernay & Montney • Four strategic assets expected to deliver rates of return >30%
Prudently managing the balance sheet	• 2015F capital program + anticipated dividends to be fully funded from cash flow + asset sales • Redeemed ~$2.3B of debt since November 2013; no incremental debt in 2015
Driving efficiencies across the business	• Drilling better wells at lower costs & increasing well inventory • Continued optimization and innovation in all operating areas • Realizing service cost reductions across the supply chain

HIGH QUALITY ASSET BASE

Focused on Four Strategic Assets

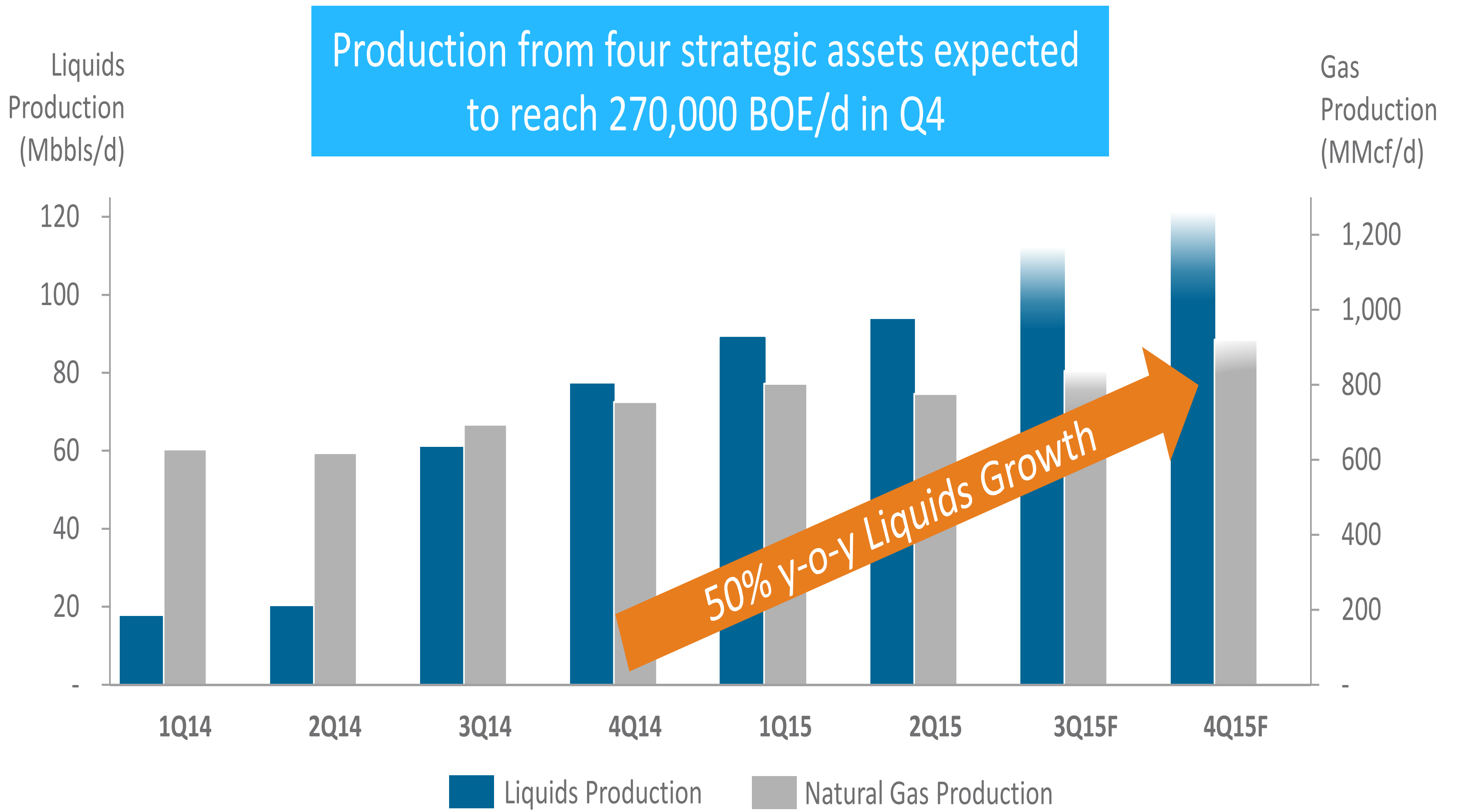
Permian, Eagle Ford, Duvernay & Montney

- Strong operating margins*
  - 2015F: Permian, Eagle Ford & Duvernay - $26/BOE
  - 2015F: Montney - $1.15/Mcfe
- Robust supply costs** ($35 - $55/BOE)
- Significant scale and running room
- Ideal for resource play hub (RPH***) development
- Good market access

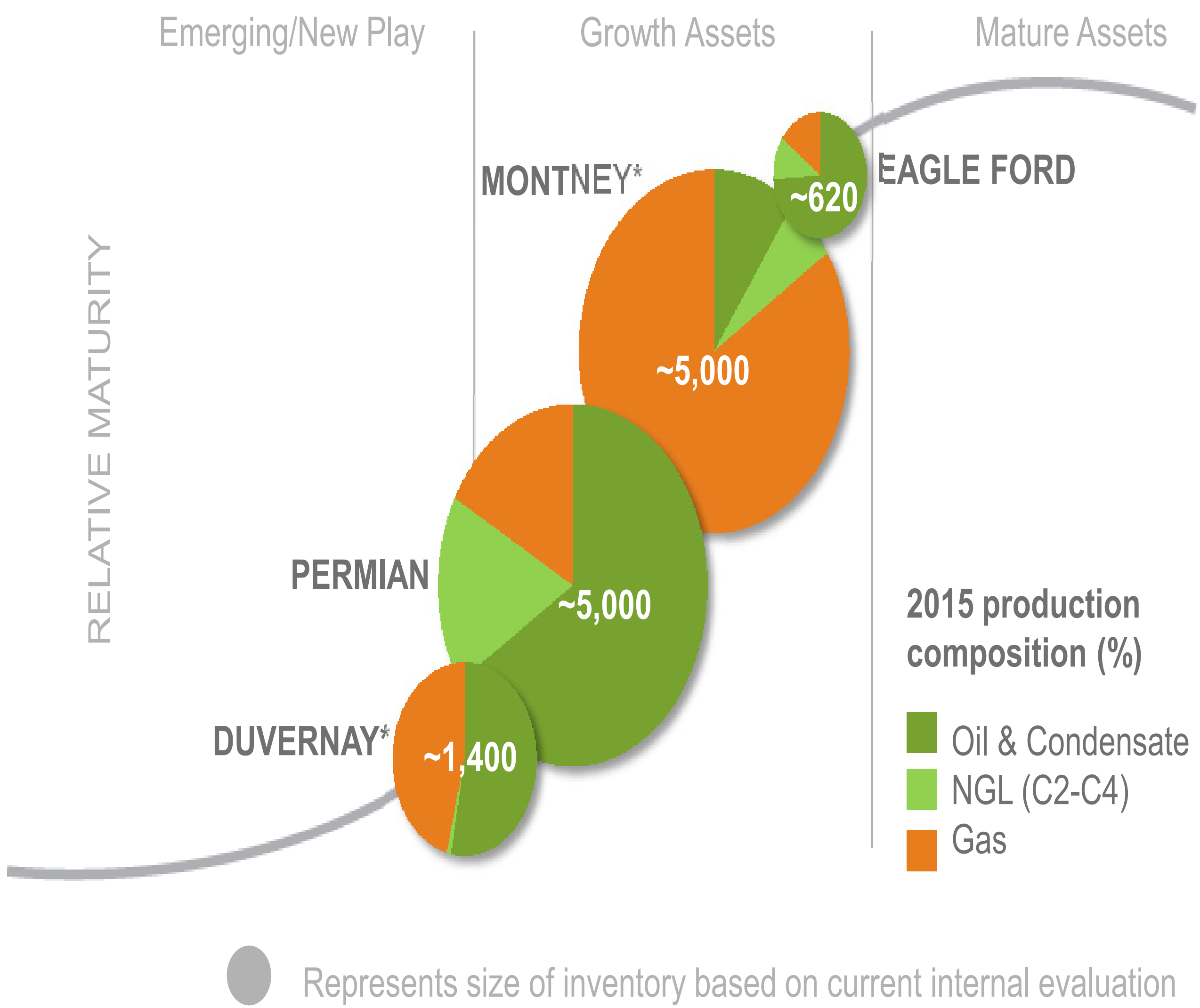
*2015F operating margins based on year-to-date actuals as at June 30th plus flat commodity price assumptions of $50/bbl WTI and $3.00/MMBtu NYMEX for the remainder of the year.
**Supply Cost is defined as the flat NYMEX/WTI price that yields an IRR of 9% and does not include land or G&A costs.
***Resource Play Hub: Encana's development model using repeatable, transferable operations techniques to reduce costs and improve safety and environmental performance

POSITIONED FOR GROWTH BEYOND 2015

Permian + Eagle Ford + Duvernay + Montney



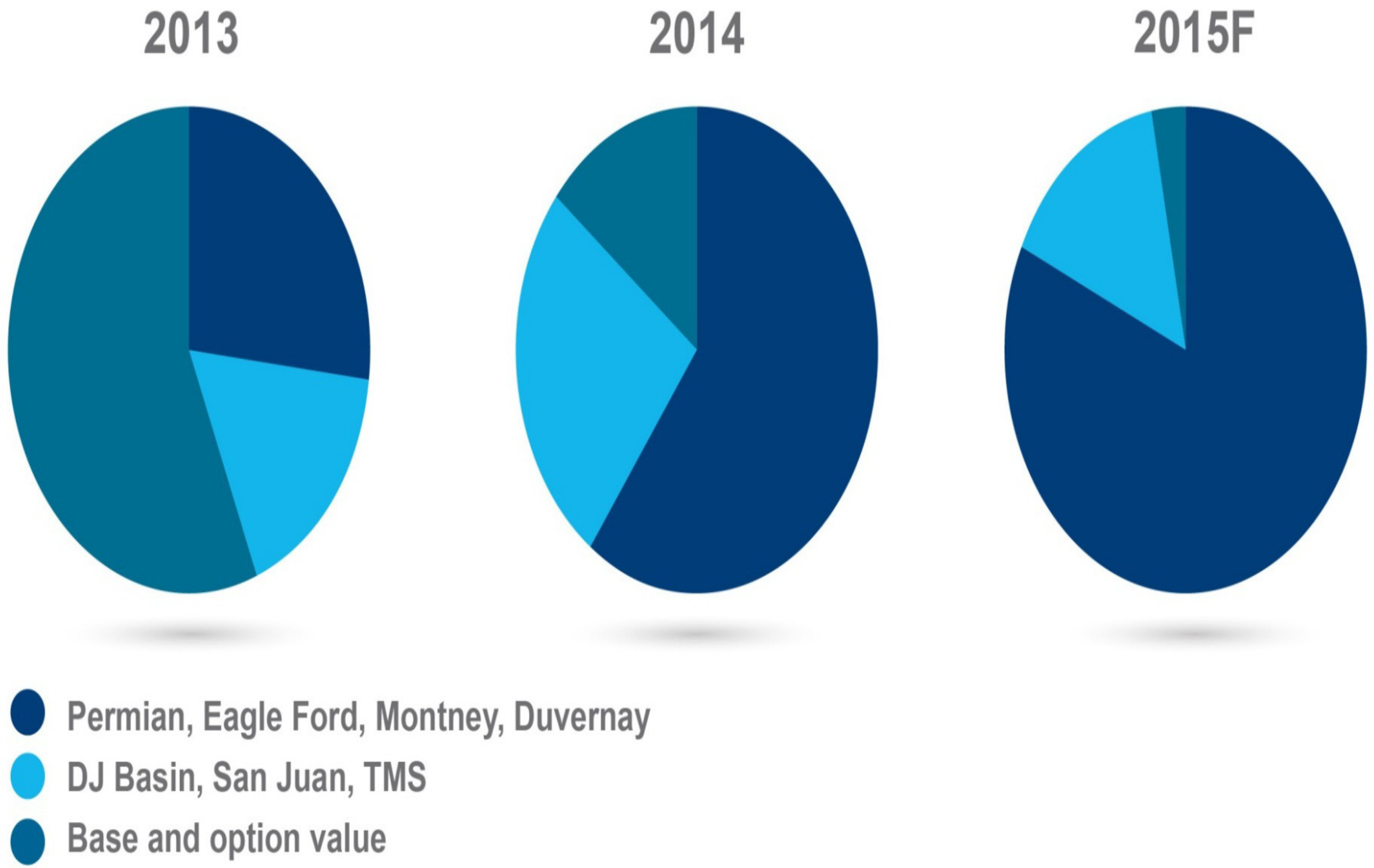
FOUR STRATEGIC ASSETS OFFER >12,000 LOCATIONS



*Encana condensate in Montney & Duvernay receiving WTI prices

FOCUSED CAPITAL PROGRAM

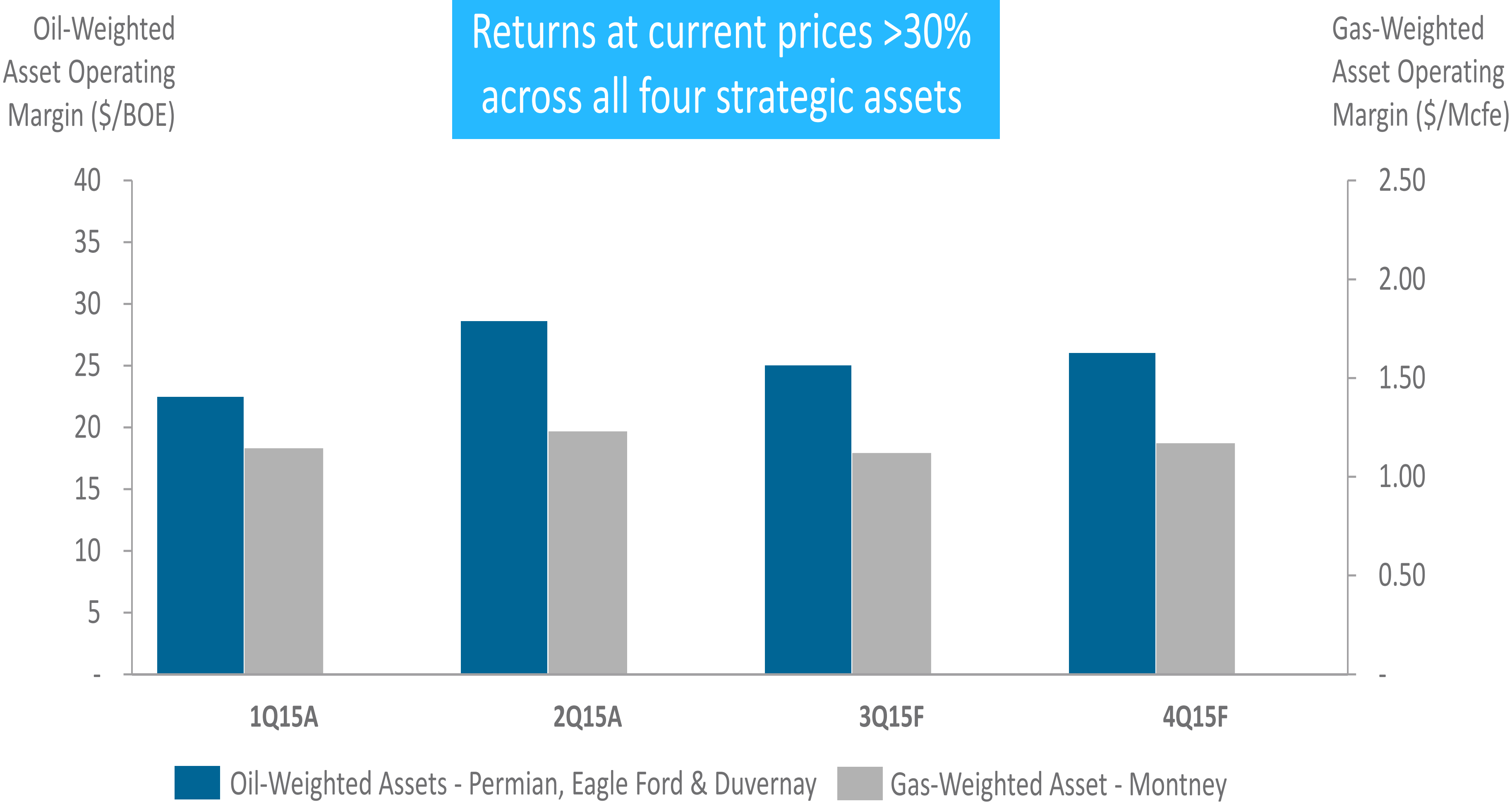
~80% of 2015 Capital Allocated to Four Strategic Assets



COMPETITIVE OPERATING MARGINS AT TODAY'S PRICES

Investing In Profitable Growth

Returns at current prices >30% across all four strategic assets



1Q & 2Q operating margins are actuals. Returns and 3Q /4Q operating margins are based on flat commodity price assumptions of $50/bbl WTI and $3.00/MMBtu NYMEX.

CAPTURING EFFICIENCIES ACROSS THE BUSINESS

Durable Cost Reductions, Focused Capital, Leaner Workforce

2/3 of $375MM 2015F efficiencies to be sustainable in higher commodity price environment

2015F capital focused on four strategic assets

Organizational realignment expected to reduce overhead costs

Improved capital efficiency

FINANCIAL POSITIONING

Ample Liquidity To Support Execution of Strategy

- **Committed to maintaining investment grade credit rating**
  - Mid-BBB ratings from Moody's, S&P and DBRS
- **$1.3 billion Q2 debt repayment**
  - No long-term debt maturities until 2019
  - ~$200 million of expected future interest expense savings resulting from debt redemptions
- **Prudently managing existing debt**
  - U.S. Commercial Paper program ($2 billion capacity) + debt repayment reduce borrowing costs by >100 bps
  - $978 million in net divestiture proceeds received as of June 30, 2015
  - Net debt of ~$5.6 billion as of June 30, 2015
- **$4.5 billion* revolving bank credit facilities amended and extended in July 2015**

2015F capital program + anticipated dividends to be fully funded from cash flow + divestiture proceeds received in Q1

*$3.1 billion available under bank credit facilities as of July 16th due to outstanding commercial paper balances.

Asset Overview

encana

PERMIAN MIDLAND BASIN

Stacked Resource Potential

- Most prolific and active onshore oil basin in North America
- Productive intervals spanning over 3,000 feet of stratigraphy

Low risk, high margin inventory

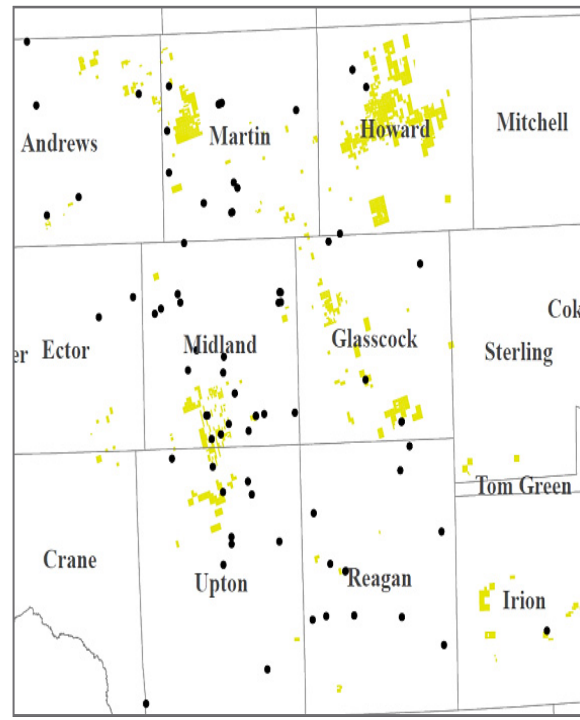
RESOURCE	Wolfcamp & Spraberry
ECA Land PIIP	~40 Billion bbls *
ECA EUR/well	650 – 1,000 MBOE
Recovery Factor %	6-15
# Stacked HZ	Up to 11

**Derived from ECA's internal evaluation*

Well Inventory positions ECA for growth beyond 2015

	Glasscock	Howard	Martin	Midland/Upton
Middle Spraberry	-	-	180	110
Lower Spraberry	145	140	210	350
Wolfcamp A	430	405	305	545
Wolfcamp B	230	-	-	390
Wolfcamp C, D/Cline Strawn/Atoka	555	140	370	495
Clearfork Canyon Shale	TBD: Upside Zones New Wells Indicate Prospective 2016 Testing Trials			
Total	**1,360**	**685**	**1,065**	**1,890**

Permian Midland Basin Industry Activity



ECA Land
Current HZ Rigs in the Midland Basin (June 2015)

PERMIAN

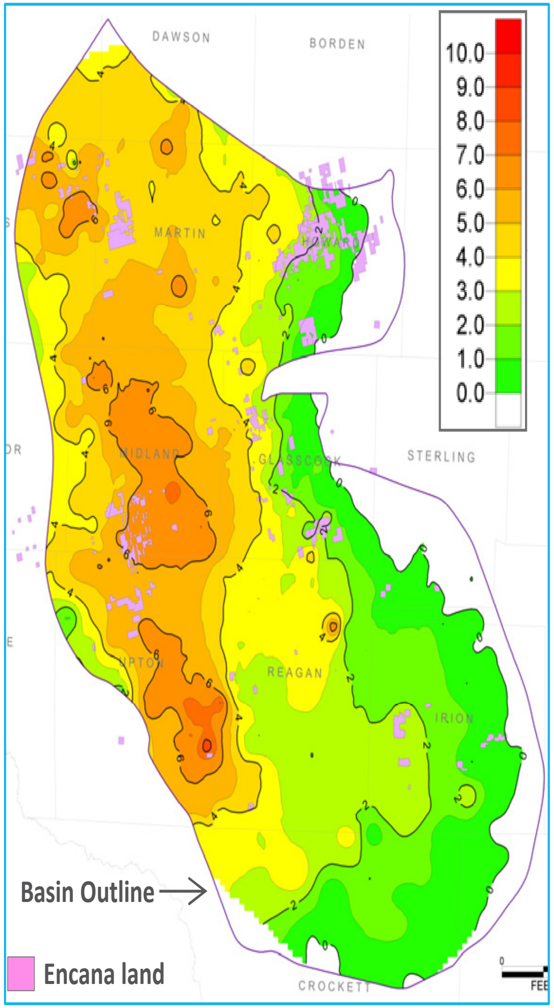
2015 Program

- Focused on optimizing well performance, capital efficiency, supply chain consolidation, developing midstream & marketing plan
- Horizontal program to integrate RPH* model into operations
  - Better well design, lower costs, greater efficiencies
- Position Encana to be among the best operators in the play
- Grow annualized production
  - Focus on horizontal drilling program
- Deliver flexible midstream & market access solutions to protect growth targets

FY 2015 Plan (Net)

2015 Rig Count	2015 Rig Release	2015 Wells on Stream	2015 Capital	2015 Q4 Production
8 – 12	170 – 180	180 – 200	$650 - $750MM	50 MBOE/d

Well-Positioned Relative to Producing Horizons



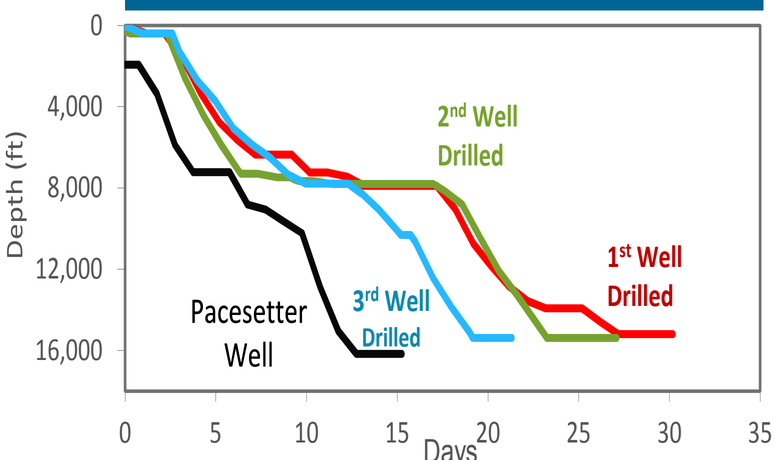
*RPH = Resource Play Hub: Encana's development model using repeatable, transferable operations techniques to reduce costs and improve safety and environmental performance

PERMIAN

Q2 2015 Update

- **TXL H2101 on production at 1,100 bbls/d and 1.1 MMcf/d**
  - 2,000 lbs/ft frac design; 4,574' lateral length
- **Davidson 24-8H on production at 900 bbls/d and 1.3 MMcf/d**
  - 4,000 lbs/ft frac design; 4,450' lateral length
- **Current target D&C $6.4MM***
- **2015 HZ program focused on Wolfcamp A, B, C and Lower Spraberry**
- **Driving efficiencies**
  - HZ rig fleet now fully converted to fit-for-purpose rigs
  - 10 fracs/day
- **Executed oil gathering agreement**
  - Pipeline to gather 50% of production by year end
  - Improves operating margins by up to $2/bbl
- **53 net wells coming on production in Q3**

Average Spud-to-Rig Release



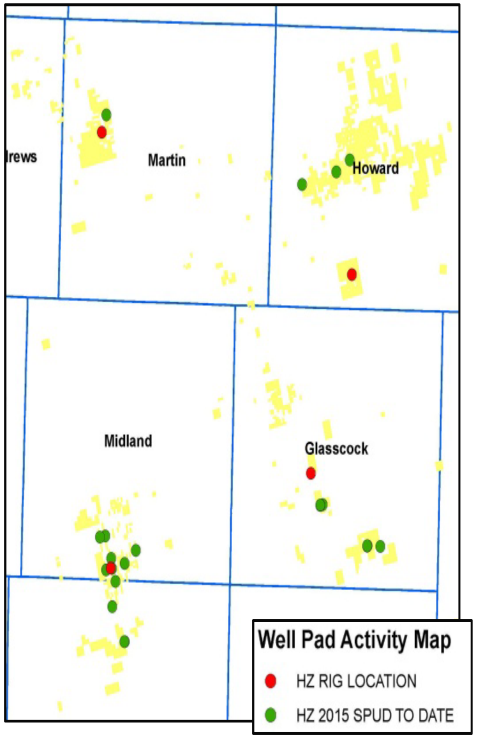
*D&C normalized to 7,100' lateral length

PERMIAN

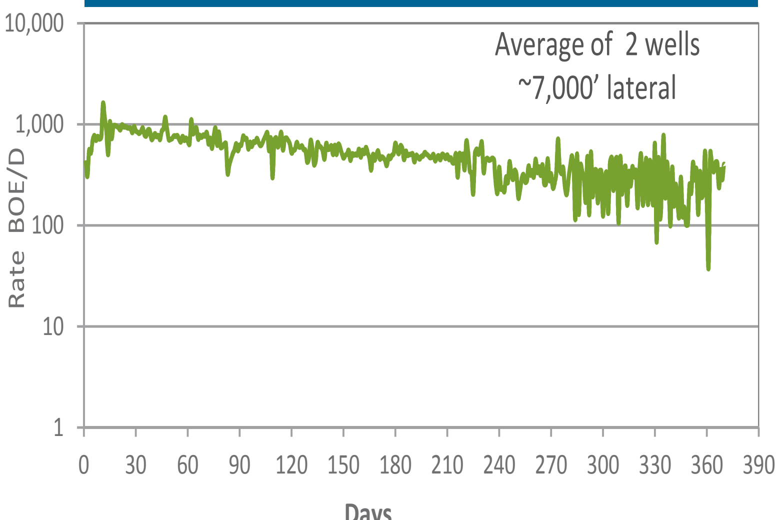
Inventory and Well Performance

County	Gross HZ Inventory	Targeted Zones	1H15 Gross Wells Vert./HZ	2015 Gross Wells Vert./HZ	Inventory Type Curve EUR (MBOE)
Glasscock	1,360	WC A & B	12 / 9	17 / 16	600 – 1,000
Howard	685	WC A	22 / 9	40 / 14	700 – 900
Martin	1,065	WC B, LS, Cline	18 / 3	34 / 12	700 – 900
Midland/Upton	1,890	WC A, B & C	17 / 16	28 / 23	600 – 900
TOTAL	**~5,000**		**69 / 37**	**119 / 65**	

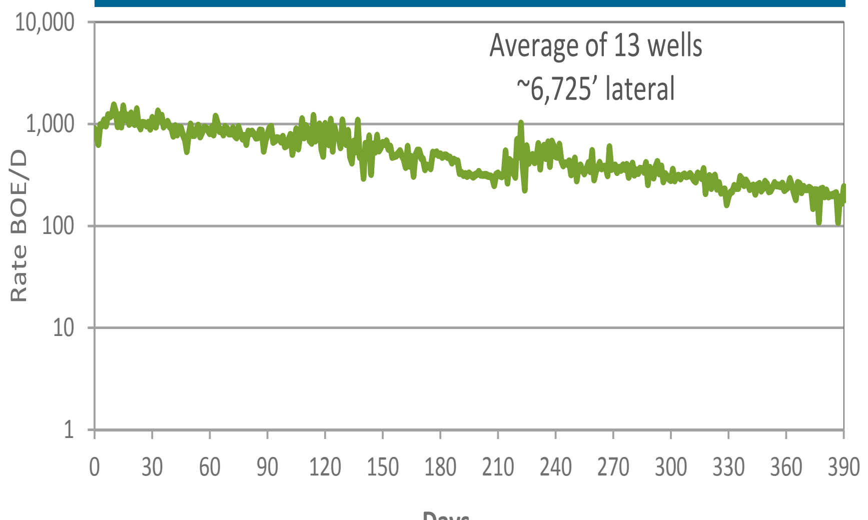
Note: Inventory based on 40-80 acres well spacing, EUR normalized to 7,100' lateral length
WC = Wolfcamp, LS = Lower Spraberry
Does not include additional potential from untested zones



Martin County Lower Spraberry Well Performance



Midland/Upton County Wolfcamp B Well Performance



PERMIAN – CURRENT PROGRAM

Key Modeling Statistics

	Glasscock		Howard A	Martin		Midland/Upton		
	Wolfcamp A	Wolfcamp B	Wolfcamp A	Lower Spraberry	Wolfcamp B	Wolfcamp A	Wolfcamp B	Wolfcamp C
Gross Inventory (#)	430	230	405	210	250	545	390	400
Gross HZ 2015 Wells (#)	12	4	14	10	2	4	18	1
WI %	85	85	90	96	96	89	89	89
IP30 (bbls/d)	950	700	875	900	800	775	900	725
EUR/Well (MBOE)	970	700	880	875	790	800	875	700
D_i (decline factor)*	84%	84%	84%	82%	84%	84%	84%	84%
b-factor*	1.4	1.4	1.4	1.2	1.4	1.4	1.4	1.4
Average Lateral Length (ft.)	7,500	7,500	8,000	7,000	7,000	6,000	6,000	6,000
D&C Well Cost $MM	6.3	6.4	6.4	6.9	7.3	6.2	6.4	6.5

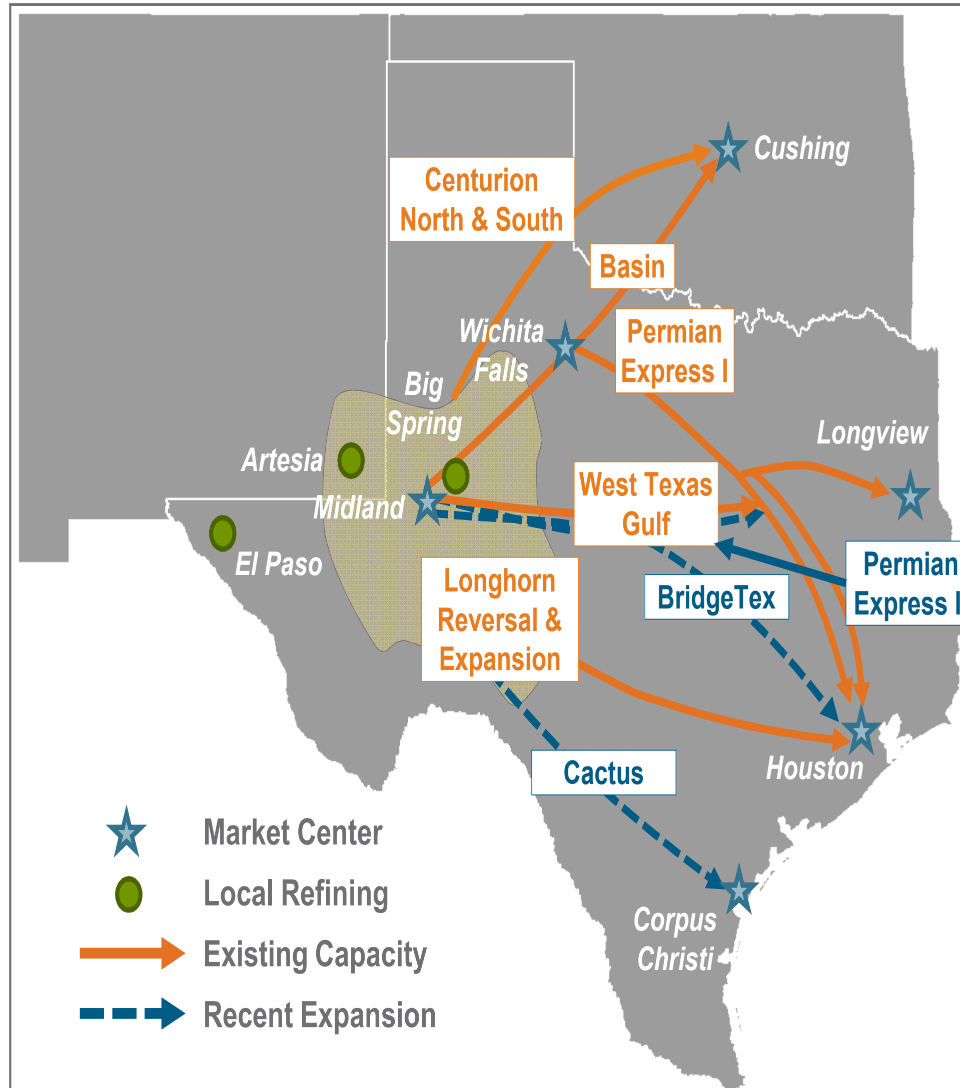
**D_i factor & b-factor for use with Arps' decline equation.*

Note: Oil gravity 42 API, heat content 1,350 Btu/scf

PERMIAN BASIN MARKET FUNDAMENTALS

Close Proximity to Market, Extensive Infrastructure in Place

- **Well-developed transportation network**
- **Pipeline expansions have alleviated basin export constraints**
  - Permian differentials have tightened in relation to Cushing and Gulf Coast markets
- **Infrastructure expected to exceed supply over the next few years**

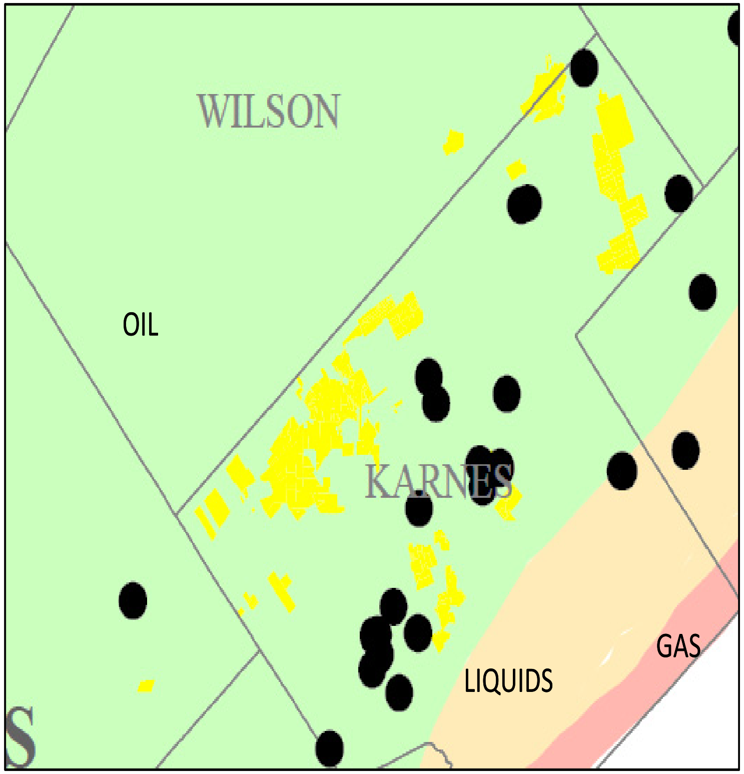


EAGLE FORD

Core Position in a Premier Oil Play

- **Largely contiguous position in the Karnes Trough**
  - Core of the core of the Eagle Ford
- **Acreage primarily lies in the condensate / volatile oil window**
  - Most active and profitable trend in the Eagle Ford
- **Will leverage ECA's resource play expertise**
- **Weighted heavily to liquids**
  - ~85% of production
- **Premium oil margin with good access to markets**
- **Highly conducive for further down-spacing**

Eagle Ford Karnes County Industry Activity



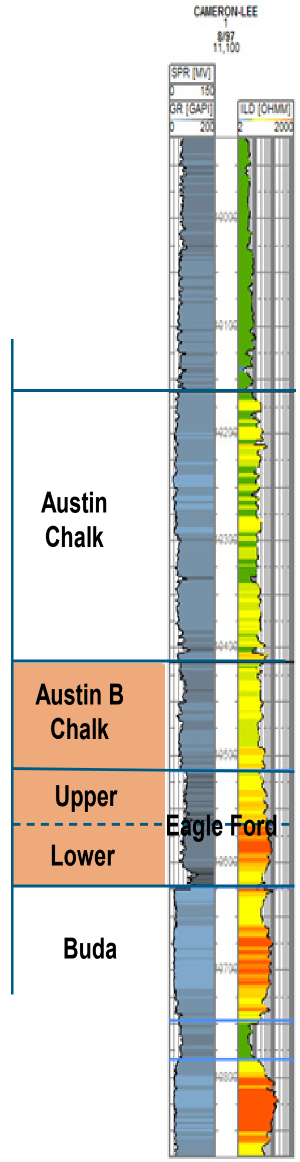
ECA Land
Current HZ Rigs in the Karnes County (June 2015)

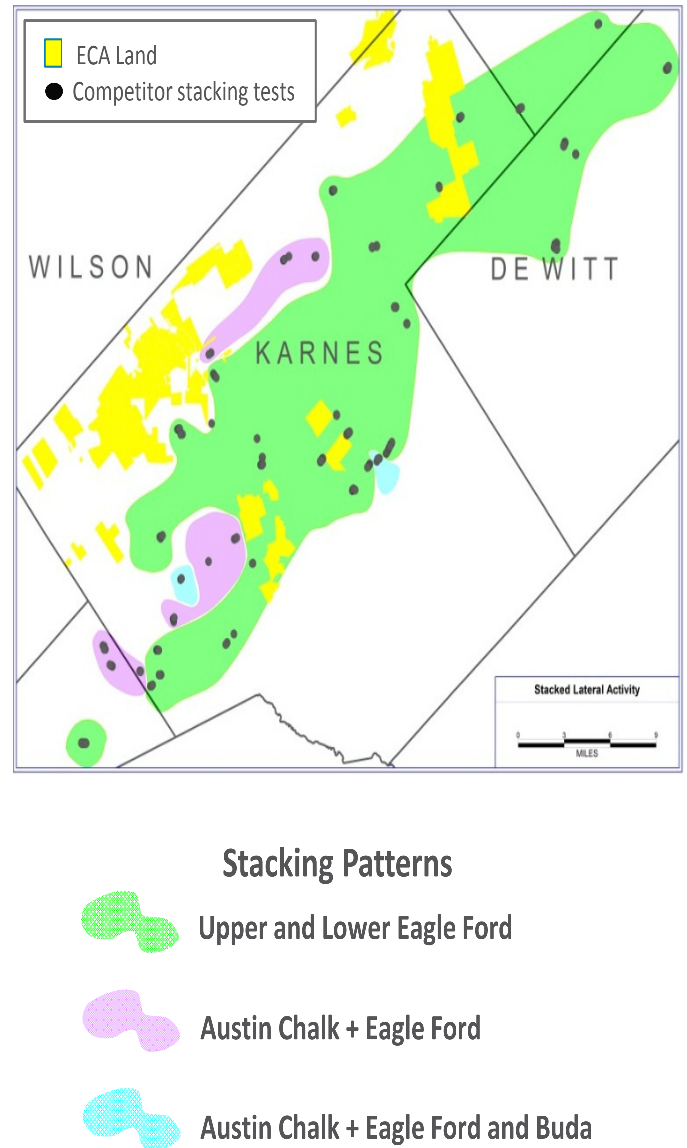
EAGLE FORD
2015 Program

- Increasing Inventory
- Position Encana to be among the best operators in the play
- Decrease well costs by optimizing drilling and completions
- Future inventory potential
  - Testing the Graben area
  - Testing Upper Eagle Ford
- Enhanced base performance

FY 2015 Plan (Net)

2015 Rig Count	2015 Rig Release	2015 Wells on Stream	2015 Capital	Q4 Production
2 – 3	55 – 65	70 – 80	$500 - $600MM	57MBOE/d



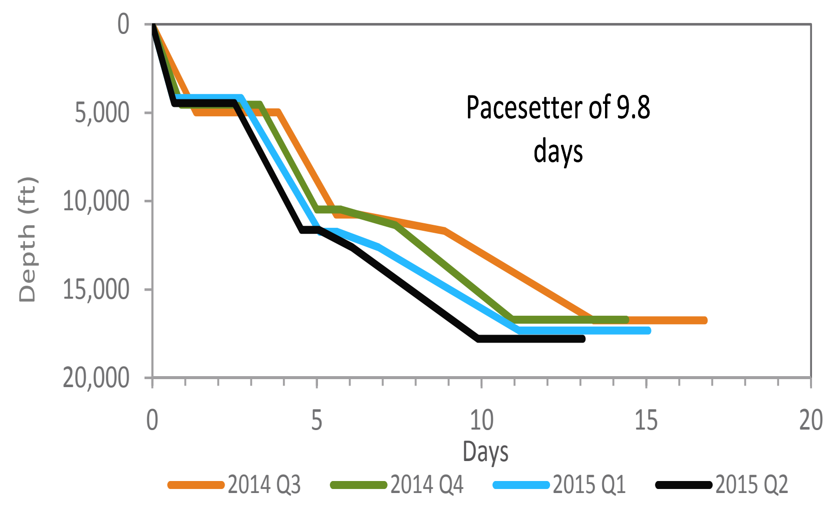


EAGLE FORD

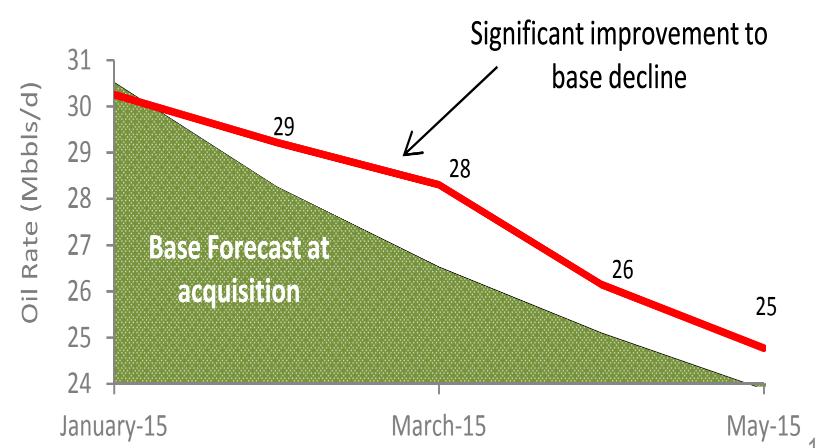
Q2 2015 Update

- **Recent Graben well on production at 1,300 bbls/d and 675 Mcf/d**
- **Current target D&C $5.6MM***
- **Increasing inventory (75% increase from time of acquisition)**
  - Planning to test Upper Eagle Ford in fourth quarter 2015
- **Driving efficiencies**
  - Reducing cycle time
  - Cluster spacing, larger frac volumes and higher sand concentration driving production performance
- **Kenedy Area, Patton Trust South Facility (PTS)**
  - Significant growth in oil and gas production, 17 PTS wells to come on in Q3
  - Increased PTS facility capacity to >18,000 bbls/d of oil, ~50 MMcf/d of gas
- **Base decline cut in half through first half of 2015**

Continuous Improvement in Drilling Cycle Time



Base Production Improvement



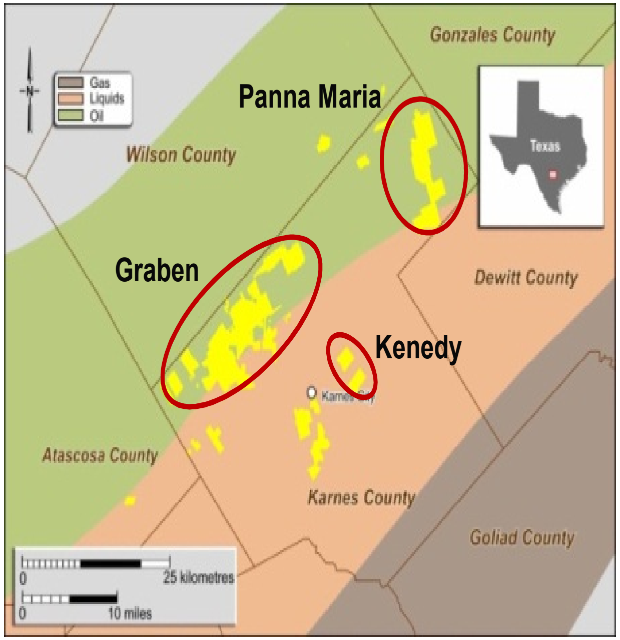
* *D&C to 5,000' lateral length*

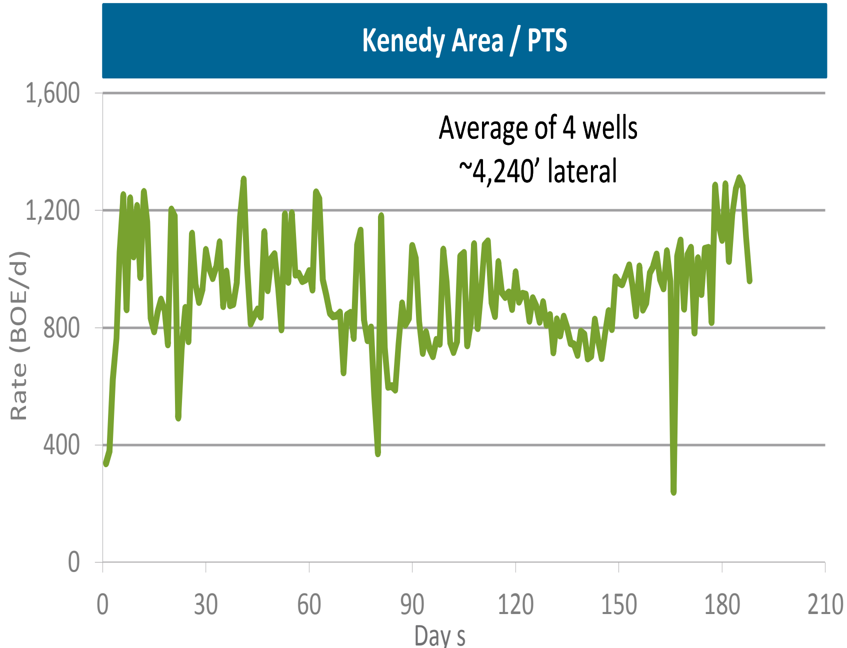
EAGLE FORD

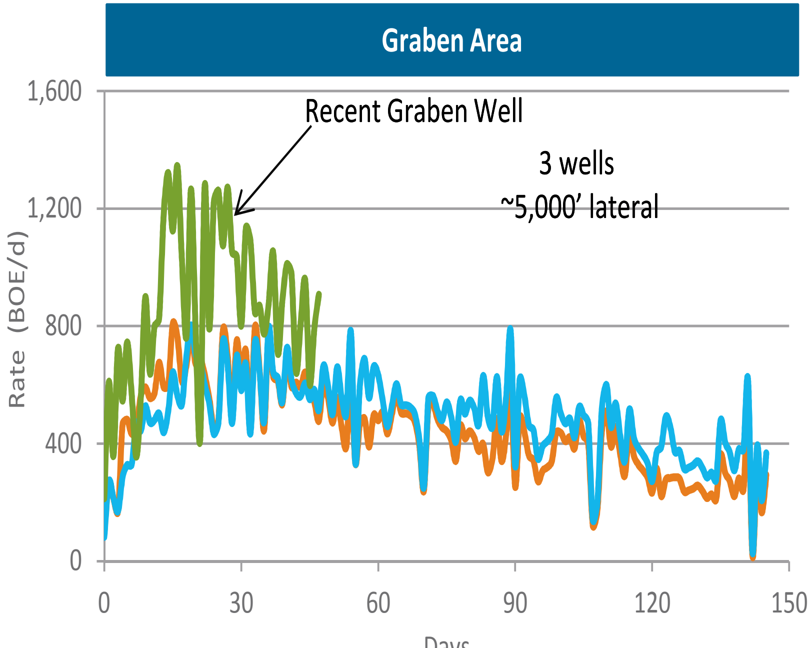
Inventory and Well Performance

Type Curve Areas	Gross Inventory	1H15 Gross Wells	2015 Gross Wells	Inventory Type Curve EUR (MBOE)
Kenedy PTS	120	30	41	800 - 900
Graben	300	7	7	400 - 500
Panna Maria	200	7	22	500 - 620
TOTAL	620	44	70	

Note: Inventory based on 30-40 acres well spacing, EUR normalized to 5,000' lateral length
Does not include potential from untested zones







EAGLE FORD – CURRENT PROGRAM

Key Modeling Statistics

	Kenedy	Panna Maria	Graben
Gross Inventory (#)	120	200	300
Gross 2015 Wells (#)	41	22	7
WI %	100	98	98
IP30 (bbls/d)	930	875	780
EUR/Well (MBOE)	800 – 900	500 – 620	400 – 500
D_i (decline factor)*	80	81	80
b-factor*	1.2	1.2	0.9
Average Lateral Length (ft.)	5,000	5,000	5,000
D&C Well Cost $MM	5.6	5.6	5.6

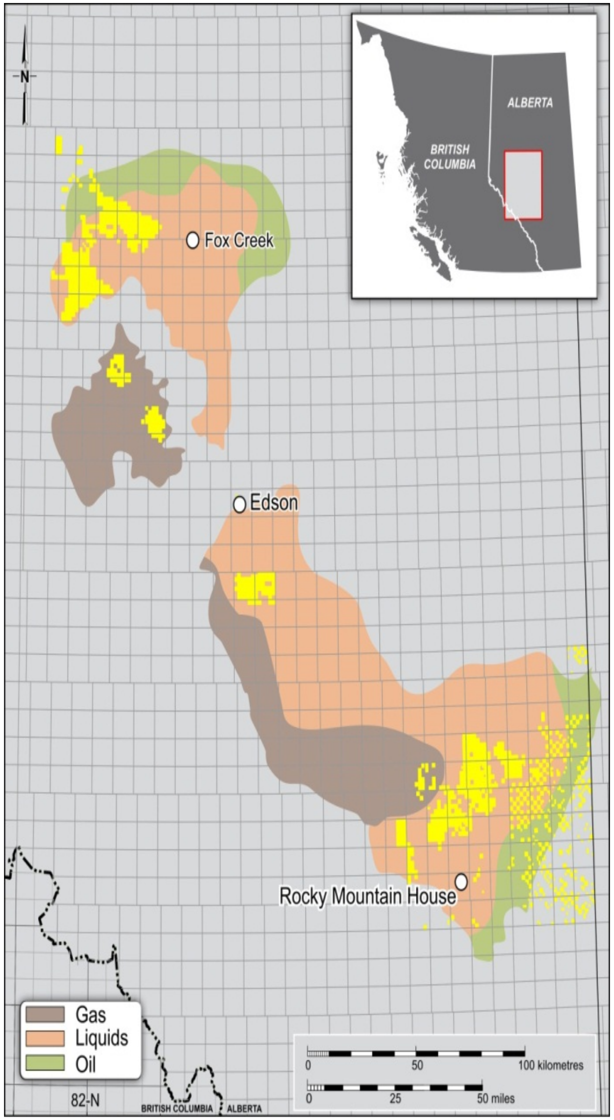
**D_i factor & b-factor for use with Arps' decline equation.*

Note: Oil gravity 42 - 55 API, heat content 1,300 Btu/scf

DUVERNAY

Premier Position in World Class Reservoir

- **Massive resource**
  - Estimated total resource of 443 Tcf gas, 11.3 Bbbls NGLs, 61.7 Bbbls oil *(source: AER: AGS Open File Report October 2012; medium case)*
- **Huge potential growth engine for Encana, capable of producing ~50,000 BOE/d**
- **Encana holds 1/3 of high-graded liquids fairway**
- **Robust condensate market, premium price to Gulf Coast**
- **PetroChina JV reduces Encana's capex, leverages economics**
- **Industry-leading operating efficiencies**
  - Dual rig/dual frac crews per pad
  - Water and road infrastructure allowing for year-round operations
- **Takeaway solution in place**
  - Long-term Rich Gas Premium (RGP) agreement with Aux Sable
  - Condensate transported on Pembina's Peace Pipeline



DUVERNAY

2015 Program

- **Significant well cost reductions**
- **Some of the highest EUR wells in North America***
- **High margin production**
- **Accelerate development in Simonette**
  - Grow liquids production by ~200% y-o-y
- **Deliver midstream project expansions**
  - 2015F exit gathering and processing capacity of 105 MMcf/d natural gas, 20 Mbbls/d liquids
- **Leverage secured transportation capacity to downstream markets**
  - Additional firm transportation capacity on Alliance pipeline to Chicago
  - Firm liquids transportation capacity on Pembina Peace pipeline

FY 2015 Plan (Net)

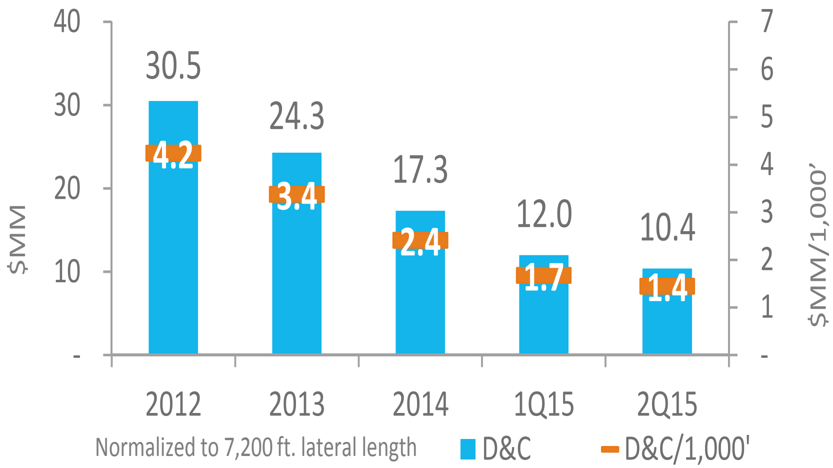
2015 Rig Count	2015 Rig Release	2015 Wells on Stream	2015 Capital	Q4 Production
2 – 3	14 – 18	20 – 25	$200 – 250MM	17 MBOE/d

Source: ITG Report 07/08/15

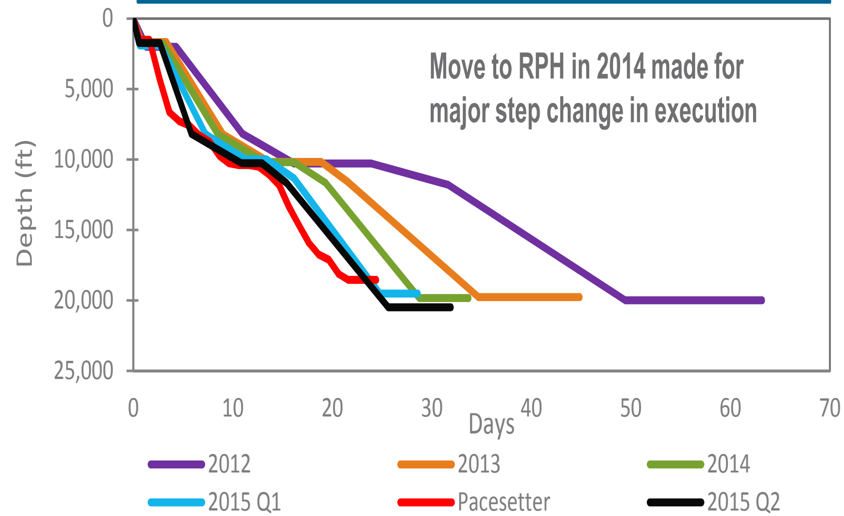
DUVERNAY

Q2 2015 Update

13% Quarter-over-Quarter Improvement

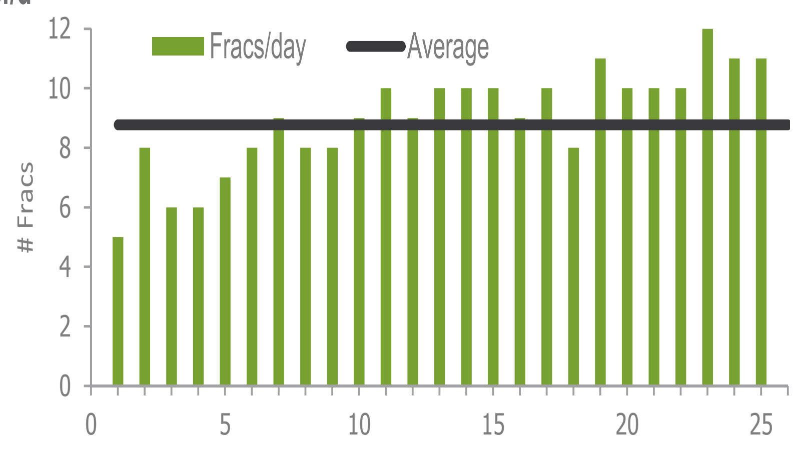


Continued Drilling Improvements



- 16-11 well on production at 2,000 bbls/d condensate & 11.5 MMcf/d
- 14-20 & 12-06 pad wells on production at 1,340 bbls/d condensate and 8.2 MMcf/d*
- Current target D&C $9.8MM**
- Driving efficiencies
  - Bit performance reducing drilling cycle time
  - Dual frac spreads – reduction of 28 days cycle time & $0.7MM/well
  - Facility run time increased to >93%
- Water infrastructure fully operational
  - $1MM/well savings
  - Eliminates trucking and improves operating margin by $2/BOE

Dual Frac Crew Success at 14-20 Pad (6 wells)



*Production (average 4 wells, lateral length 8,790') **D&C Cost normalized to 7,200' lateral length

DUVERNAY

Inventory and Well Performance

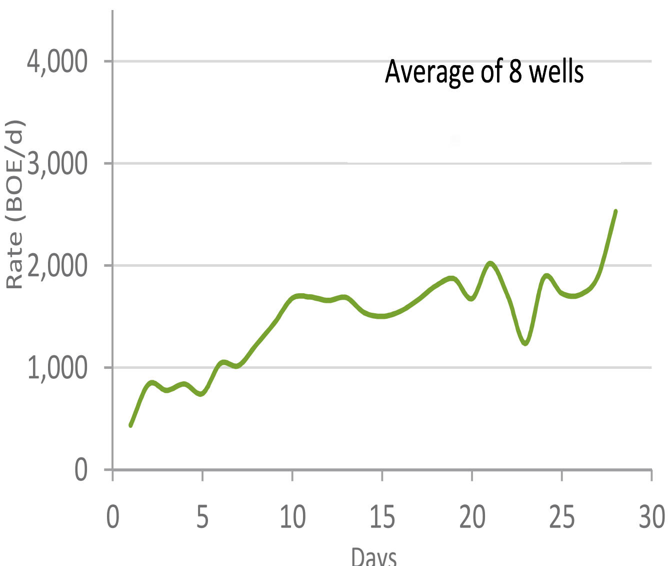
Simonette Type Curve	Simonette Gross Inventory	1H2015 Gross wells	2015 Gross Wells	Type Curve Condensate EUR (MBbl)	Inventory Type Curve EUR (MBOE)
5 – 65 bbls/MMcf	80	0	0	175 - 245	1,000 – 1,400
65 – 150 bbls/MMcf	150	0	2	350 - 550	1,200 – 1,600
150 – 250 bbls/MMcf	400	13	24	400 - 650	1,000 – 1,400
> 250 bbls/MMcf	460	2	2	300 - 400	700 - 900
TOTAL	**1,100**	**15**	**28**		

Note: Inventory based on 125 acre spacing, EUR based on 8,200' to 8,800' lateral length, ex of inventory outside Simonette

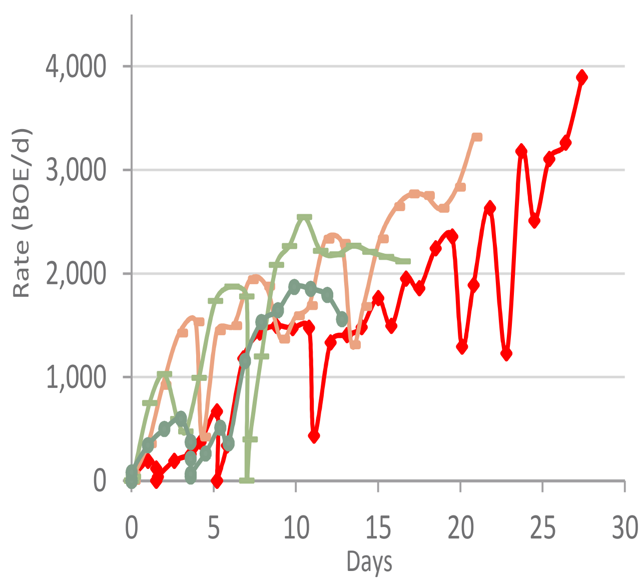
Most Recent Well Performance

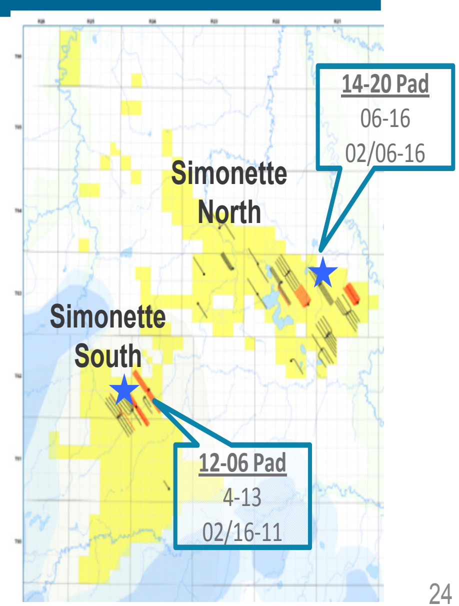
Well	Condensate Rate (bbls/d)	Gas Rate (MMcf/d)	Oil Equiv (BOE/d)
04-13-062-25	1,550	10.5	3,300
02/16-11-062-25	2,000	11.5	3,900
06-16-063-21	1,000	6.6	2,100
02/06-16-063-21	800	4.5	1,550

Simonette Q2 Well Performance



Most Recent Well Performance





DUVERNAY – CURRENT PROGRAM

Key Modeling Statistics

	Condensate Gas Ratio 65 – 150 bbls/MMcf	Condensate Gas Ratio 150 – 250 bbls/MMcf
Gross Inventory (#)	150	400
Gross 2015 Wells (#)	2	24
WI %	50%	50%
IP30 (MMcf/d)	6 – 8	5 – 6.5
EUR/Well (MBOE)	1,200 – 1,600	1,000 – 1,400
Condensate Yields (bbl/MMcf)	65 – 150	150 – 250
D_i Gas (decline factor)*	70	70
D_i Condensate (decline factor)*	80	80
b-factor (gas)	1.4 - 1.5	1.3 - 1.4
b-factor (oil)	1.0 – 1.1	0.9 – 1.1
Average Lateral Length (ft.)	8,200-8,860	8,200-8,860
D&C Well Cost ($MM)	11.2 – 12.1	11.2 – 12.1

**D_i factor & b-factor for use with Arps' decline equation.*

Note: Condensate gravity 52 API, heat content 1,270 Btu/scf

DUVERNAY JOINT VENTURE

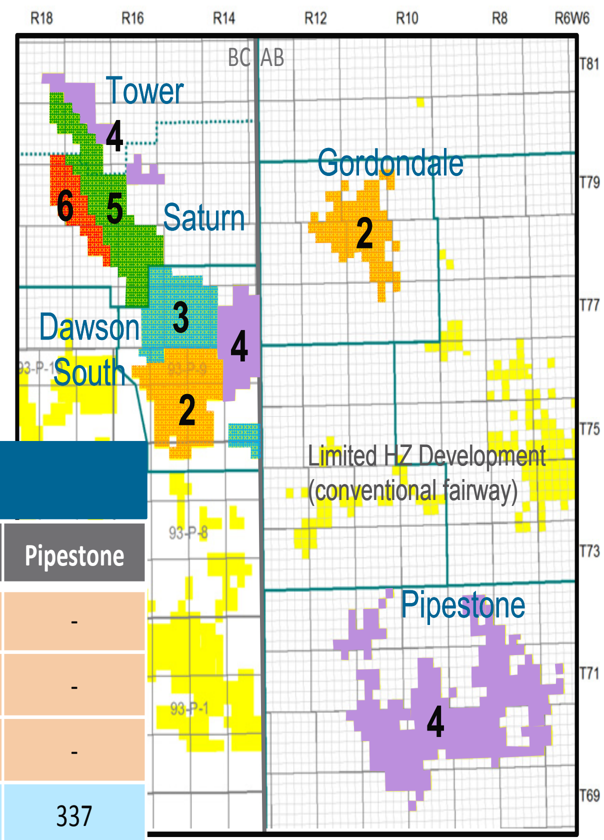
- **Brion (formerly Phoenix, a subsidiary of PetroChina) agreed to invest C$2.18 billion for 49.9% working interest**
  - C$1.18 billion up front cash in 2012
  - Further investment of C$1.0 billion during the commitment period
- **2015F carry capital $240 million**
- **Carry capital expected to extend through 2016**

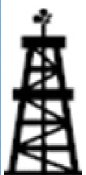
MONTNEY

Decades of Low Cost Inventory

- **Massive running room and scale**
  - Potential of >2 Bcf/d and >50,000 bbls/d on Encana lands
  - >25 years of drilling inventory
  - Large contiguous core land positions
  - Encana acreage in most proven region of the fairway

Number of Stackable Laterals

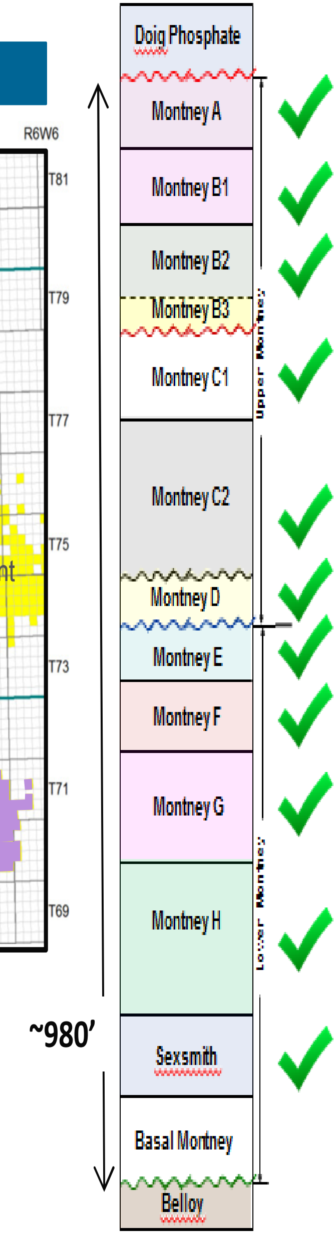




Well Inventory positions ECA for growth beyond 2015

		Tower	Saturn	Dawson South	Gordondale	Pipestone
A/B1	Upper Montney	55	400	380	-	-
B2/B3/C1	Upper Montney	125	293	-	-	-
C2/D/E	Upper Montney	130	402	115	-	-
F/G	Lower Montney	150	435	695	-	337
G	Lower Montney	-	-	-	-	
H	Lower Montney	-	-	-	60	36
Sexsmith		140	415	565	40	177
Total		600	1,945	1,755	100	550

✔ Tested Horizontal Targets in Inventory



MONTNEY

2015 Program

- Development focus in liquids rich region
- Maximize well deliverability and accelerate payout
- Deliver ~20% (gross) growth in low-cost natural gas production
- Continue to increase efficiencies
- Utilize water hub in completions
- Expand gathering and processing capacity to exit 2015 with 1,100 MMcf/d of gross capacity

FY 2015 Plan (Net)

2015 Rig Count	2015 Rig Release	2015 Wells on Stream	2015 Capital	Q4 Production
2 – 3	15 – 25	40 – 50	$220 - $280MM	146 MBOE/d

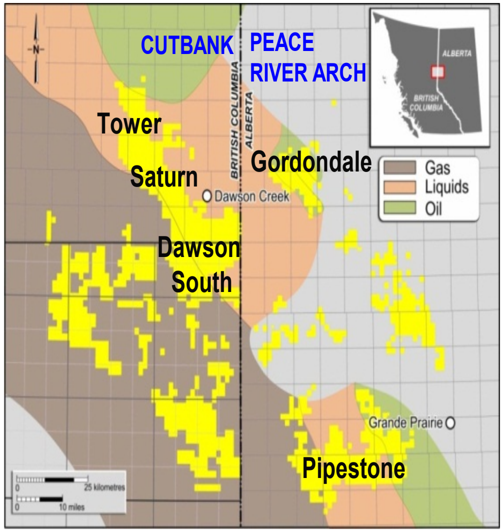
Water Resource Hub

MONTNEY

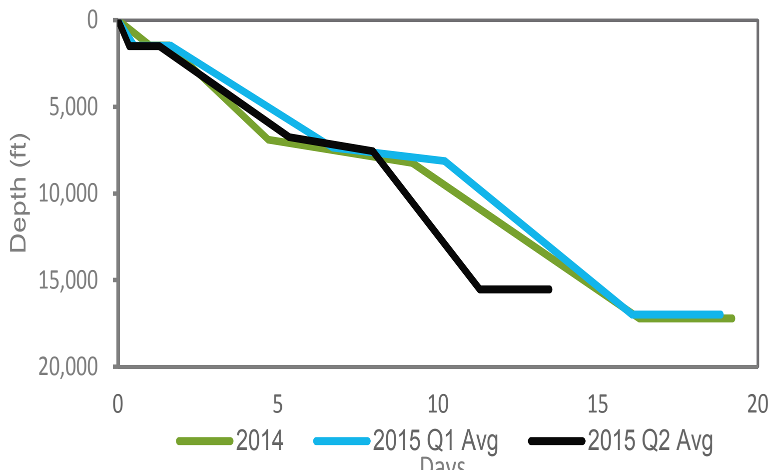
Q2 2015 Update

- C9-35 well on production at 400 bbls/d condensate and 10 MMcf/d
- D12-05 well on production at 375 bbls/d condensate and 7.5 MMcf/d
- C30-G well on production at 12 MMcf/d flat for 200 days and flowing pressure still 1,200 psi
- Current target D&C $6.0MM*
- Driving efficiencies
  - Drilled fastest Montney well to date in Tower (9 days)
  - High intensity fracs expected to deliver 33% uplift in IP and EUR
- Increasing condensate rich inventory
  - Dawson South and Pipestone
- Dawson North compressor station on stream in June
  - 200 MMcf/d & 2,000 bbls/d gross
- Challenges with third party restrictions

Inventory Becoming More Liquids Rich



Average Spud- to-RR Days vs Depth



*D&C and production normalized to 8,200' lateral length

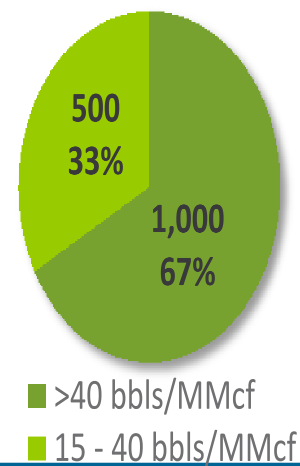
MONTNEY

Inventory and Well Performance

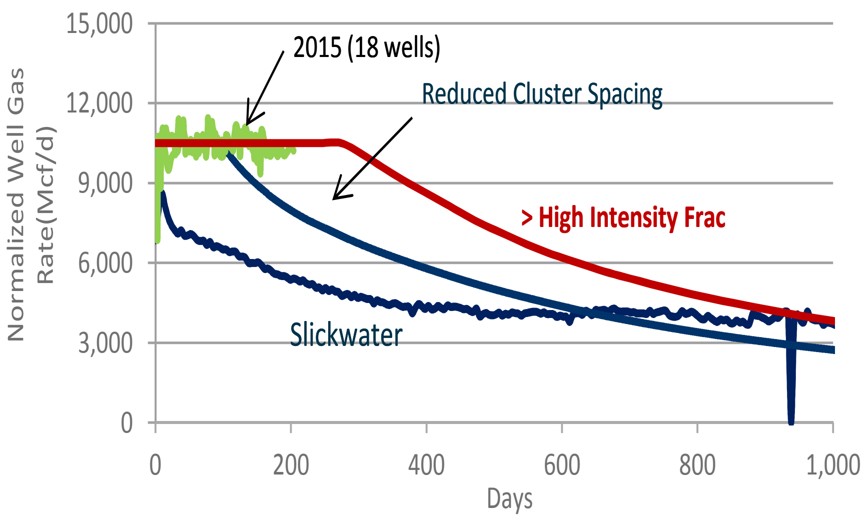
Type Curve Areas	Gross Inventory	1H2015 Gross wells	2015 Gross wells	Gas EUR (Bcf)	NGL EUR (Mbbls)	Condensate EUR (Mbbls)	Inventory Type Curve EUR (MBOE)
Tower	600	9	9	11 - 14	330 - 430	330 - 470	2,400 – 3,100
Saturn	1,945	10	10	11 - 18	55 - 90	74 - 190	2,000 – 2,700
Dawson South	1,755	2	4	13 - 21	6 - 100	30 - 380	2,300 – 3,700
Pipestone Gordondale	650	1	4	5 - 11	75 - 236	110 - 442	1,200 – 2,400
TOTAL	**~5,000**	**22**	**27**				

Inventory based on 10-80 acre spacing, EUR normalized to 8,500' lateral length
Does not include additional potential from untested zones

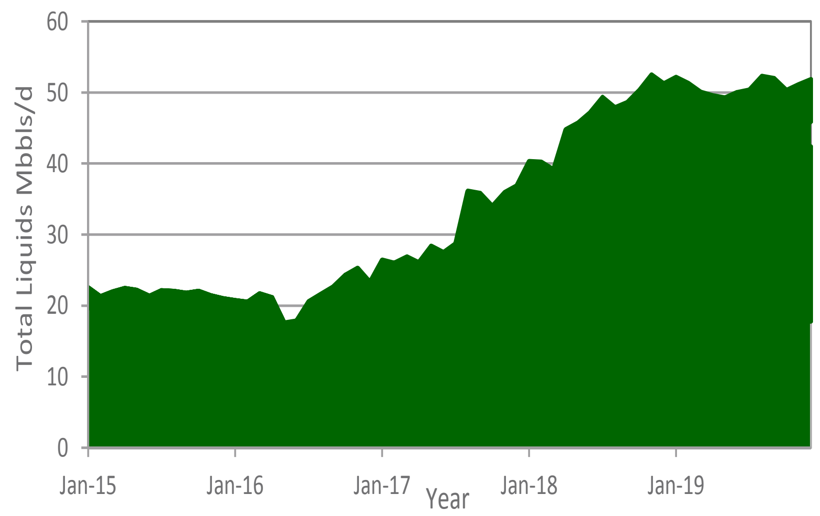
>1,500 Oil and Liquids Inventory



Impact of High Intensity Frac to IP and EUR



Montney Liquids Growth Outlook



MONTNEY – CURRENT PROGRAM

Key Modeling Statistics

	Tower	Saturn	Dawson South
Gross Inventory (#)	600	1945	1755
Gross 2015 Wells (#)	9	10	4
WI%	60	60	60
IP30 (MMcf/d)	5 - 7	10 - 14	7 - 14
EUR/Bcfe	15 – 19	12 – 20	13 – 19
EUR/Well (MBOE)	2,400 – 3,100	2,000 – 2,700	2,300 – 3,700
Condensate Yield (bbls/MMcf)	30 – 90	6 – 20	15 – 55
D_i (decline factor)*	60 – 70	65 – 75	65 – 75
b-factor*	1.0 – 1.4	0.6 – 2.5	0.6 - 2.0
Average Lateral Length (ft.)	8,855	8,855	8,855
D&C Well Cost $MM	6.1	6.6	7.4

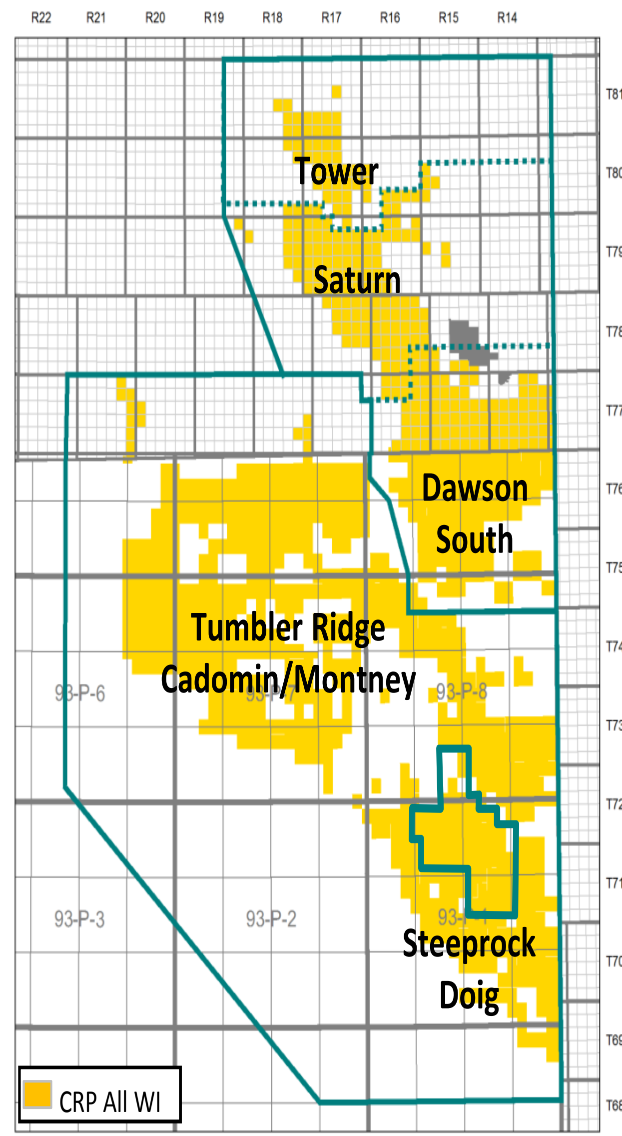
**D_i factor & b-factor for use with Arps' decline equation.*

Note: Condensate gravity 40 API, heat content 1,200 Btu/scf

MONTNEY

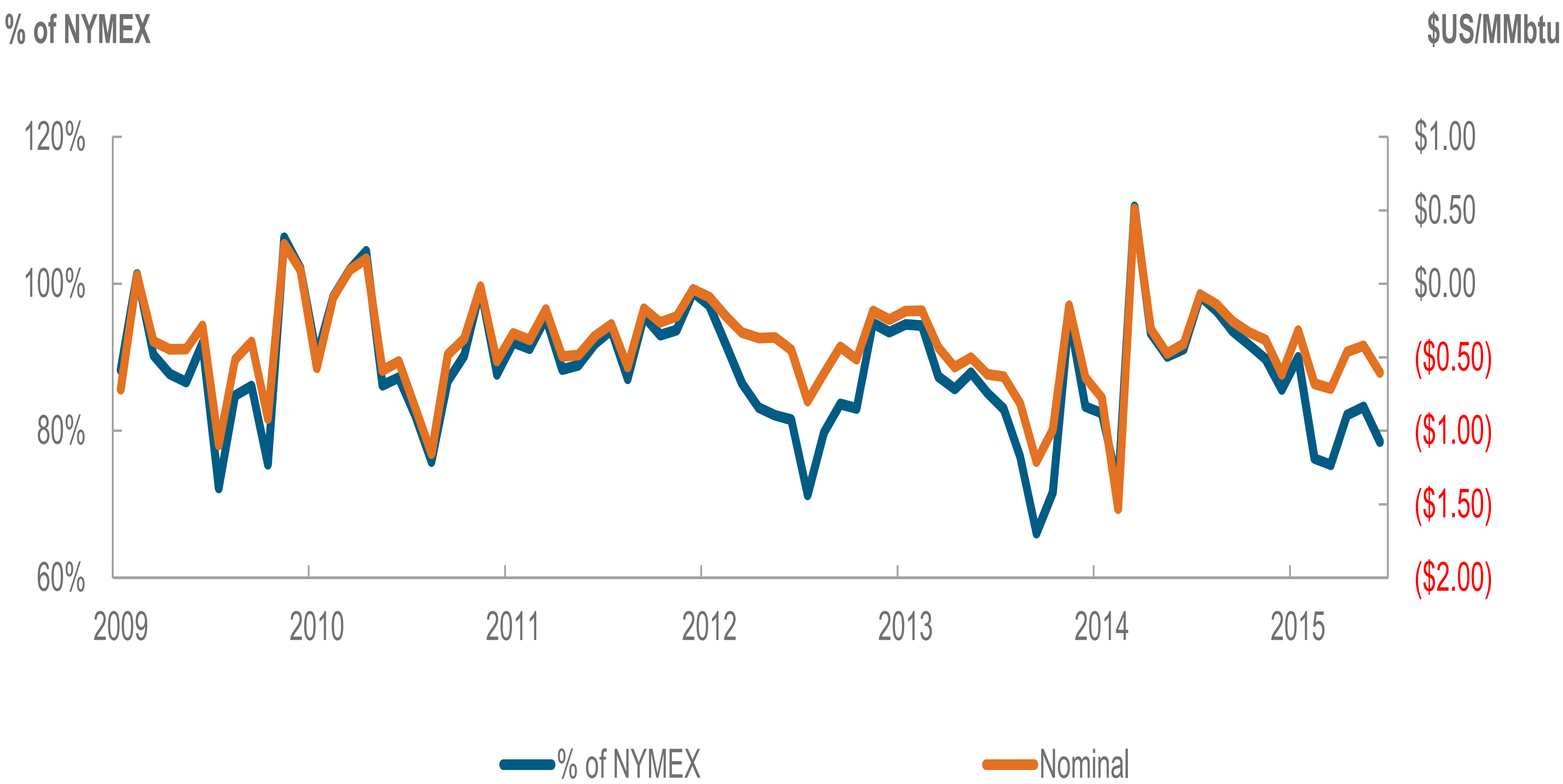
Cutbank Ridge Partnership (CRP)

- **Partnership with a subsidiary of Mitsubishi**
  - Encana: 60% interest
  - Mitsubishi: 40% interest
- **Development areas**
  - Montney: Tower, Dawson North, Dawson South and Tumbler Ridge
  - Cadomin
  - Steeprock Doig
- **Investment structure (C$2.9B)**
  - C$1.45 billion upfront in 2012
  - Further investment of C$1.45 billion during the commitment period
- **Mitsubishi also funds its 40% of the Partnership's future capital investment**
- **2015F third party capital ~$100 million**
- **Third party capital expected to extend through 2019**



AECO BASIS HISTORICAL PERFORMANCE

AECO basis has traded between 70% - 100 % of NYMEX since 2009



Source: Encana Fundamentals, CGPR, NYMEX, Various Pipelines

DJ BASIN, SAN JUAN, TMS

Key Statistics

	DJ Basin	San Juan	TMS
Land (net acres):	51,000	206,000	200,000
Average working interest:	37%	58%	60%
RPH type curve EUR/well:	540 – 840 Mboe	400 – 600 MBoe	600 – 700 MBoe
Well inventory (gross):	1,100	700+	~1,000
RPH well costs (DCT):	$4.5 – $5.5 million	$4 – $5 million	$11 – $13 million
2015F Production (net)			
Oil/field condensate:	10,000 – 11,000 bbls/d	4,500 – 5,500 bbls/d	4,000 – 4,500 bbls/d
NGLs:	5,000 – 5,500 bbls/d	1,000 – 1,500 bbls/d	-
Natural gas:	50 – 60 MMcf/d	10 – 15 MMcf/d	-
2015F Capital (net):	$190 – $210 million	$70 – $100 million	$30 – $60 million
2015F Wells:	15 –20 (net)	2 – 5 (net)	2 – 5 (net)
2015F rigs:	1	0.25	0.25
Supply cost*:	$35 – $45/boe	~$35 – $65/boe	$45 – $55/boe

*Supply Cost is defined as the flat NYMEX/WTI price that yields an IRR of 9% and does not include land or G&A costs. Reflects joint venture leverage

BETTER WELLS, LOWER COSTS, BIGGER INVENTORY

- Achieving strong well performance across the 4 strategic assets
- Liquids production accelerating in 2H 2015
- Realizing sustainable operating and capital cost reductions
- Maintaining a solid balance sheet

One. Agile. Driven.

A culture of success

Supplemental

DISCIPLINED FOCUS ON PROFITABLE GROWTH

VISION: Leading North American oil and gas resource play company

- High quality rocks
- Scale and running room
- Operational excellence
- Portfolio optionality

STRATEGY: Disciplined focus on generating profitable growth

- Capital allocated to high return, strategic and scalable assets
- Acceleration of oil/liquids growth
- Reduce cost structures and drive efficiency improvements

GOAL: Growing shareholder value

- Sustainable business model through commodity cycle
- Cash flow per share growth
- Investment grade credit rating
- Dividend paying*
- Unlocking value from massive resource base

*Dividends are subject to the discretion of the Board of Directors

WINNING CORE COMPETENCIES

Aligned Organizational Structure

TOP TIER RESOURCE

David Hill

- High quality rocks
- Scale
- Running room
- Oil and gas

OPERATIONAL EXCELLENCE

Mike McAllister

- Best in class operators differentiate
- Focus on:
  - efficiency
  - integrated thinking
  - maximize netbacks

MARKET FUNDAMENTALS

Renee Zemljak

- Understand the “trade winds”
- Strong linkage to capital allocation
- Actively managing volatility

CAPITAL ALLOCATION

Sherri Brillon

- Disciplined & dynamic
- Strong link to strategy
- Centrally controlled
- Informed
- High return projects

DEMONSTRATING RESULTS AT TODAY'S PRICES

Better Wells, Lower Costs, Increasing Inventory

- **Achieving strong well performance across the 4 strategic assets**
  - Permian IP rates of >1,000 bbls/d oil
  - Eagle Ford Graben IP rate of 1,300 bbls/d oil and 675 Mcf/d of gas; inventory growing to 620 locations
  - Duvernay well costs of <$11 million and well results up to 2,000 bbls/d of condensate and 11.5 MMcf/d of gas
  - New Montney condensate-rich area: Well results of 300-400 bbls/d of condensate and 10 MMcf/d of gas, condensate-rich inventory growing to ~1,500 locations
- **Liquids production accelerating in the second half of the year**
  - 7 consecutive quarters of liquids production growth since launching new strategy
  - 4 strategic assets expected to produce 270,000 BOE/d in Q4
  - 100 wells on production in late June and Q3 in Permian & Eagle Ford
- **Realizing sustainable operating and capital cost reductions**
  - On track to achieve 2015 target of $375 million in efficiencies
- **Maintaining a solid balance sheet**
  - $1.3 billion debt repayment
  - Amended and extended credit facilities of $4.5 billion to 2020

BUILDING MOMENTUM FOR 2H 2015

Q2 In Review

- 87% y-o-y increase in total liquids volumes
- 78% YTD total liquids production comprised of oil and condensate*
- >80% Q2 capital to four strategic assets
- $140 million Q2 net divestiture proceeds
- Decreased total debt by 17% vs. year-end 2014

	Q2 2015	YTD 2015
Upstream Operating Cash Flow** Excluding Realized Hedging ($MM)	315	769
Upstream Operating Cash Flow** Including Realized Hedging ($MM)	479	1,181
Total Cash Flow ($MM)	181	676
- $ per share, diluted	0.22	0.85
Operating Earnings (Loss) ($MM)	(167)	(148)
- $ per share, diluted	(0.20)	(0.19)
Weighted average common shares outstanding - diluted (MM)	841.2	799.5
Capital Investment ($MM)	743	1,479
Net Acquisitions & (Divestitures) ($MM)	(140)	(978)
Natural Gas (MMcf/d)	1,568	1,712
Total Liquids* (Mbbls/d)	127.3	124.0
Total Production (MBOE/d)	388.7	409.3
Net Debt*** ($MM)	5,616	5,616

*Includes plant condensate. **Upstream operating cash flow is defined as revenues, net of royalties, less production and mineral taxes, transportation and processing and operating expenses for each of the respective Canadian and USA operations. ***Net debt defined as long term debt, including current portion, less cash and cash equivalents

ON TRACK TO MEET 2015 GUIDANCE

Disciplined & Results-Focused Approach To Capital Spending

	2015F
Total Cash Flow ($B)	1.4 – 1.6
- per common share, diluted ($/sh)	1.70 – 1.95
Weighted Average Common Shares Outstanding – diluted* (millions)	821
Capital Investment ($B)	2.0 – 2.2
Natural Gas (MMcf/d)	1,600 – 1,700
Oil & Field Condensate (Mbbls/d)	85 – 95
NGLs (Mbbls/d)	45 – 55
Total Liquids (Mbbls/d)	130 – 150
Total Production (MBOE/d)	395 – 430
Upstream Operating Expense** ($/BOE)	4.60 – 4.90
Transportation & Processing ($/BOE)	8.75 – 9.00
Administrative Expense** ($/BOE)	1.50 – 1.65
DD&A Rate ($/BOE)	9.75 – 10.25

- **Capital, cash flow, production guidance unchanged**
  - DD&A rate reduced
- **Expect to achieve mid to high end of cash flow range**
- **$978 million net divestiture proceeds received YTD**
- **Fully funded capital program + dividends with ~$100 million of expected surplus cash**
- **~Two-thirds of planned 2015 capital spent in 1H**
- **2H capital focused on four strategic assets**

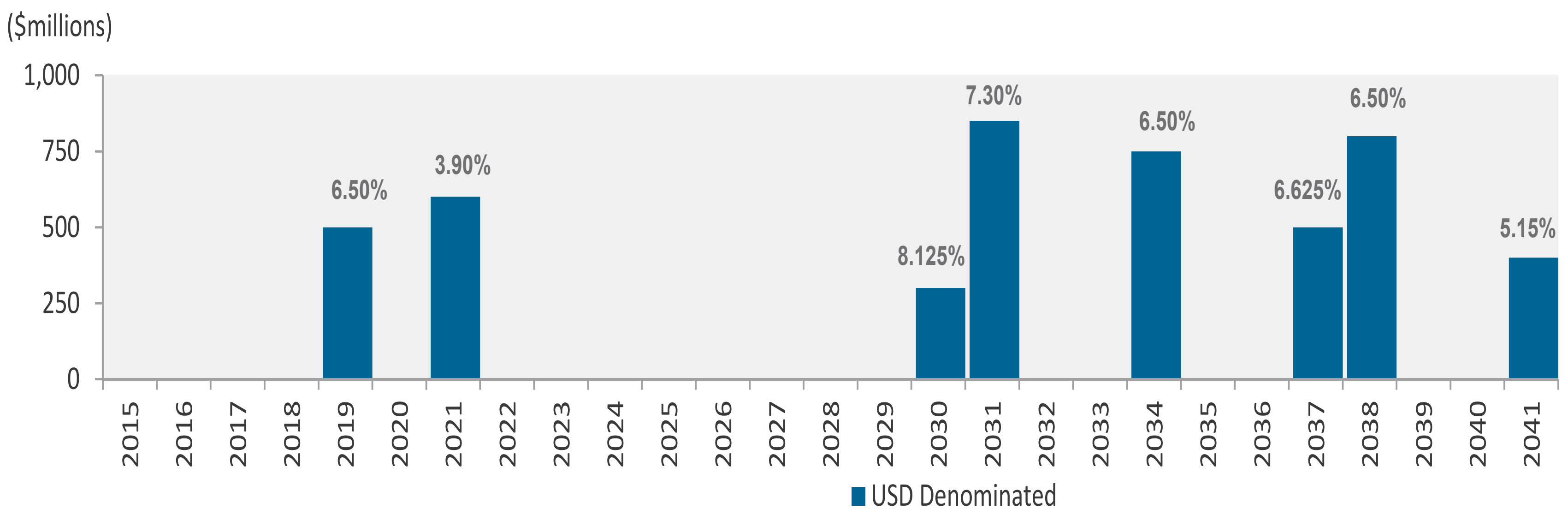
*Common shares outstanding of 842.5 million at June 30, 2015. **Excludes impacts of long-term incentives and restructuring charges.

PRUDENT FINANCIAL MANAGEMENT

Debt Portfolio as at June 30, 2015

- ~$1.3 billion debt repayment in April 2015
  - Debt redemption to save ~$200 million in future interest expense
- Financial flexibility with no debt maturities until 2019

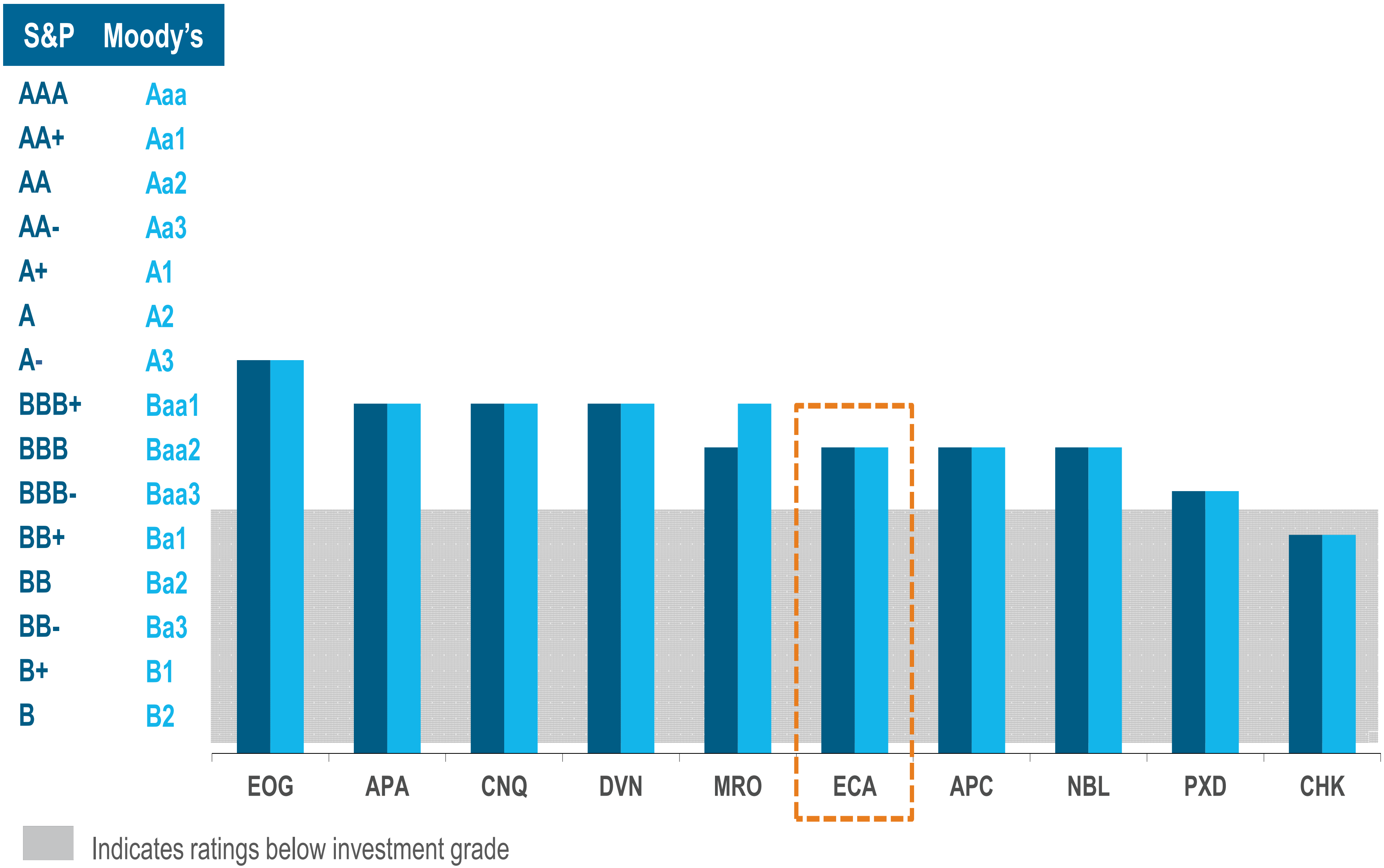
Debt Maturity Schedule*



* Excludes outstanding CP balance

CREDIT RATING COMPARISON

As of June 30, 2015



LIQUIDS VALUE CHAIN

Projected Composition of Total Liquids Production

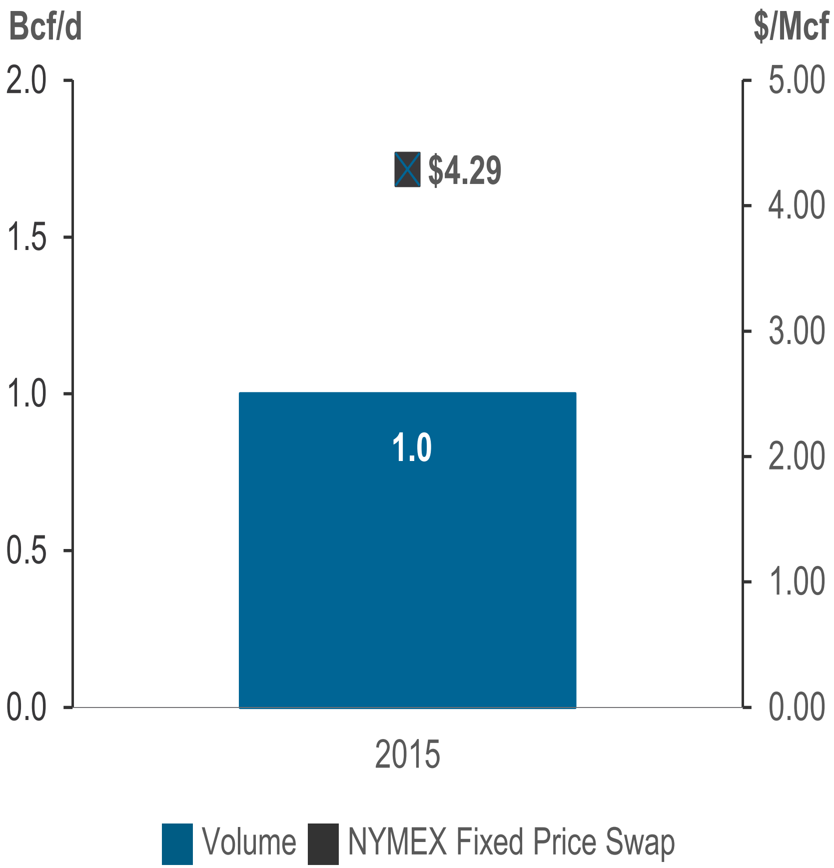
	Canada		US	
	2015F (Mbbls/d)	2015F Pricing (%WTI)	2015F (Mbbls/d)	2015F Pricing (%WTI)
Oil and Condensate*	18 – 20	84%	85 – 95	85%
Butane	2 – 4	51%	4 – 6	45%
Propane	2 – 4	6%	8 – 12	32%
Ethane	1 – 3	22%	7 – 9	4%

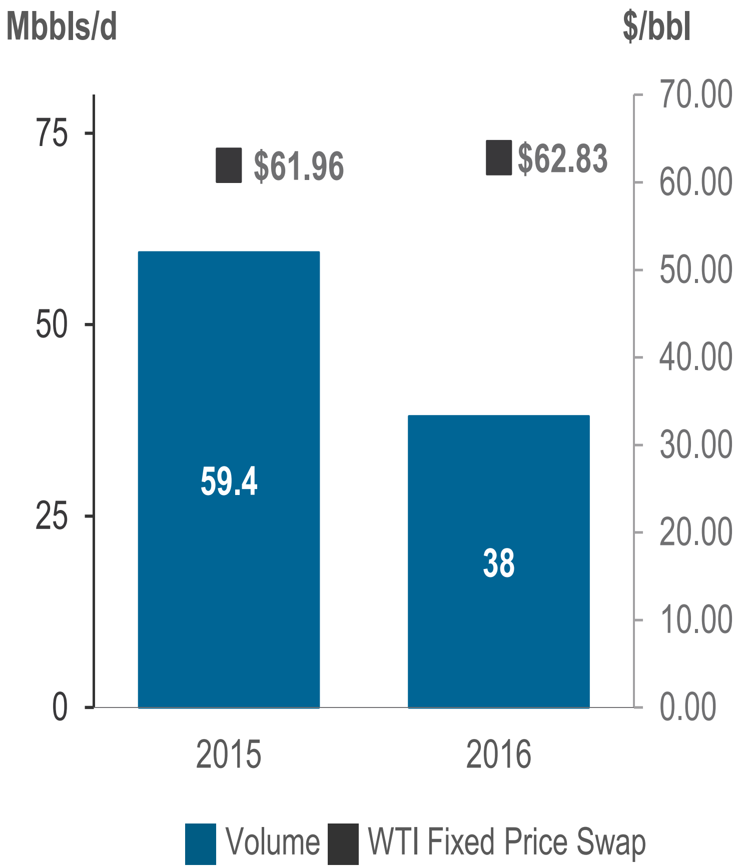
Liquids primarily comprised of higher-value products

2015F based on company guidance as at July 24, 2015.
*Includes plant condensate

HEDGING PROGRAM

Adds Greater Certainty to Cash Flow





Hedge positions as at June 30, 2015

FUTURE ORIENTED INFORMATION

This presentation contains certain forward-looking statements or information (collectively, “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements include, but are not limited to:

- expectation to accelerate liquids production growth in the second half of 2015 and the value of liquids
- number of wells for 2015 and expected production
- the potential to grow well inventory
- capital spending plans including those to grow higher margin production
- expectation of meeting the targets in the company's 2015 corporate guidance
- anticipated cash flow
- the Company’s expectation to fully fund its 2015 capital program and dividend with anticipated cash flow and proceeds from divestitures
- innovation and optimization work to improve well performance and production rates and reduce costs and cycle times
- expected rig count and rig release metrics
- expected rates of return
- continued operational and administrative cost savings and efficiencies, including reductions in G&A and interest expense
- managing balance sheet strength, preserving financial flexibility and enhancing liquidity
- anticipated third party incremental capital and joint venture carry capital
- repeatable performance of the Company’s RPH model
- anticipated benefits from the Company’s hedging strategy
- maintaining an investment grade credit rating
- improved operating margins
- anticipated success of base decline reduction initiatives
- anticipated reserves and resources and stacked resource potential
- development of midstream and marketing solutions, including increased capacity

Readers are cautioned upon unduly relying on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, these statements involve numerous assumptions, known and unknown risks and uncertainties and other factors, which can contribute to the possibility that such statements will not occur or which may cause the actual performance and financial results of the Company to differ materially from those expressed or implied by such statements. These assumptions include, but are not limited to:

- achieving average production for 2015 of between 1.60 Bcf/d and 1.70 Bcf/d of natural gas and 130,000 bbls/d to 150,000 bbls/d of liquids
- commodity prices for natural gas and liquids based on NYMEX of $3.00 per MMBtu, AECO of C$2.62 per GJ and WTI of $50 per bbl through the remainder of 2015
- U.S./Canadian dollar exchange rate of 0.80
- effectiveness of the Company’s resource play hub model to drive productivity and efficiencies
- results from innovations
- data contained in key modeling statistics
- availability of attractive hedge contracts
- expectations and projections made in light of, and generally consistent with, Encana’s historical experience and its perception of historical trends, including with respect to the pace of technological development, the benefits achieved and general industry expectation

Risks and uncertainties that may affect the operations and development of our business include, but are not limited to: the ability to generate sufficient cash flow to meet the Company’s obligations; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability of dividends to be paid; the timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; risk and effect of a downgrade in credit rating, including access to capital markets; fluctuations in currency and interest rates; assumptions based upon the Company’s 2015 corporate guidance; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana’s business as described from time to time in Encana’s most recent MD&A, financial statements, Annual Information Form and Form 40-F, as filed on SEDAR and EDGAR. Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. The forward-looking statements contained in this document are made as of the date of this document and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by these cautionary statements.

Certain future oriented financial information or financial outlook information is included in this presentation to communicate Encana’s current expectations as to its performance in 2015. Readers are cautioned that it may not be appropriate for other purposes. Ths presentation may contain references to non-GAAP measures, which do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies. These measures have been described and presented in order to provide shareholders and potential investors with additional information regarding Encana’s liquidity and its ability to generate funds to finance its operations.

ADVISORY REGARDING RESERVES DATA & OTHER OIL & GAS INFORMATION

National Instrument ("NI") 51-101 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies such as Encana engaged in oil and gas activities. Encana complies with the NI 51-101 annual disclosure requirements in its annual information form, most recently dated March 3, 2015 ("AIF"). The Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business" in the AIF. Encana has obtained an exemption dated January 4, 2011 from certain requirements of NI 51-101 to permit it to provide certain disclosure prepared in accordance with U.S. disclosure requirements, in addition to the Canadian protocol disclosure. That disclosure is primarily set forth in Appendix D of the AIF. Further, Encana obtained an exemption dated January 21, 2015 (the "2015 Exemption Order") from certain requirements of NI 51-101, to permit it to use the definition of "product type" contained in the amendments to NI 51-101 published by the securities regulatory authority in each of the jurisdictions of Canada on December 4, 2014 that came into force on July 1, 2015, as it relates to its Canadian protocol disclosure contained in Appendix A of the AIF.

Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The estimates of economic contingent resources contained in this presentation are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH"). Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum estimated, on 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. Economic contingent resources are those contingent resources that are currently economically recoverable. In examining economic viability, the same fiscal conditions have been applied as in the estimation of reserves. There is a range of uncertainty of estimated recoverable volumes. A low estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate, which under probabilistic methodology reflects a 90 percent confidence level. A best estimate is considered to be a realistic estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, which under probabilistic methodology reflects a 50 percent confidence level. A high estimate is considered to be an optimistic estimate. It is unlikely that the actual remaining quantities recovered will exceed the high estimate, which under probabilistic methodology reflects a 10 percent confidence level. There is no certainty that it will be commercially viable to produce any portion of the volumes currently classified as economic contingent resources. The primary contingencies which currently prevent the classification of Encana's disclosed economic contingent resources as reserves include the lack of a reasonable expectation that all internal and external approvals will be forthcoming and the lack of a documented intent to develop the resources within a reasonable time frame. Other commercial considerations that may preclude the classification of contingent resources as reserves include factors such as legal, environmental, political and regulatory matters or a lack of markets.

The estimates of various classes of reserves (proved, probable, possible) and of contingent resources (low, best, high) in this presentation represent arithmetic sums of multiple estimates of such classes for different properties, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of reserves and contingent resources and appreciate the differing probabilities of recovery associated with each class.

Encana uses the terms resource play, total petroleum initially-in-place ("PIIP"), natural gas-in-place ("NGIP"), and crude oil-in-place ("COIP"). Resource play is a term used by Encana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. PIIP is defined by the Society of Petroleum Engineers - Petroleum Resources Management System ("SPE-PRMS") as that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources"). NGIP and COIP are defined in the same manner, with the substitution of "natural gas" and "crude oil" where appropriate for the word "petroleum". As used by Encana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom.

In this presentation, Encana has provided information with respect to certain of its plays and emerging opportunities which is "analogous information" as defined in NI 51-101. This analogous information includes estimates of PIIP, NGIP, COIP or EUR, all as defined in the COGEH or by the SPE-PRMS, and production type curves. This analogous information is presented on a basin, sub-basin or area basis utilizing data derived from Encana's internal sources, as well as from a variety of publicly available information sources which are predominantly independent in nature. Production type curves are based on a methodology of analog, empirical and theoretical assessments and workflow with consideration of the specific asset, and as depicted in this presentation, is representative of Encana's current program. Some of this data may not have been prepared by qualified reserves evaluators or auditors, may have been prepared based on internal estimates (including PIIP and EUR), and the preparation of any estimates may not be in strict accordance with COGEH. Estimates by engineering and geo-technical practitioners may vary and the differences may be significant. Encana believes that the provision of this analogous information is relevant to Encana's oil and gas activities, given its acreage position and operations (either ongoing or planned) in the areas in question, and such information has been updated as of the date hereof unless otherwise specified. Due to the early life nature of the various emerging plays discussed in this document, PIIP is the most relevant specific assignable category of estimated resources. There is no certainty that any portion of the resources will be discovered. There is no certainty that it will be commercially viable to produce any portion of the estimated PIIP, NGIP, COIP or EUR. Further, disclosure regarding drilling locations is based on internal estimates, may include proved, probable and unbooked locations, and assume a number of wells that can be drilled per section based on industry practice and internal review. The drilling locations which Encana will actually drill will ultimately depend upon the availability of capital, regulatory and partner approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors.

30-day IP and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery. In this presentation, certain natural gas volumes have been converted to barrels of oil equivalent (boe) on the basis of six thousand cubic feet (Mcf) to one barrel (bbl). Boe may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

For convenience, references in this presentation to "Encana", the "Company", "we", "us" and "our" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.

2015F ENCANA CORPORATE GUIDANCE

US$, U.S. GAAP

July 24, 2015

Encana's 2015 planned capital program plus anticipated dividends, using the stated price assumptions, is expected to be fully funded by forecasted 2015 cash flow plus proceeds from divestitures that closed in the first quarter.

		2015F
Cash Flow ($ billions, except per share amount)		
Total Cash Flow (1)(2)		1.4 – 1.6
- Per common share, diluted ($/share)		1.70 – 1.95
Weighted average common shares outstanding – diluted (millions)		821
Capital Investment ($ billions)		
Total Capital Investment		2.0 – 2.2
Production (after royalties)		
Natural Gas (MMcf/d)		1,600 – 1,700
Oil & Field Condensate (Mbbls/d)		85 – 95
Natural Gas Liquids (Mbbls/d)		45 – 55
Liquids (Mbbls/d)		130 - 150
Total Production (MBOE/d)		395 - 430
Operating Costs ($/BOE at 6:1 ratio)		
Upstream Operating Expense (3)		4.60 – 4.90
Transportation and Processing		8.75 – 9.00
Administrative Expense (3)		1.50 – 1.65
Depreciation, Depletion and Amortization Rate (4)		9.75 –10.25
2015 Sensitivities (1) ($ millions)	**Cash Flow(2)**	**Operating Earnings(2)**
$0.50/Mcf increase/decrease in the NYMEX natural gas price	120	85
$10/bbl increase/decrease in the WTI oil price	240	160
Price Assumptions		
WTI ($/bbl)		50.00
NYMEX ($/MMBtu)		3.00
AECO (C$/GJ)		2.62
FX (U.S./Cdn)		0.80

1. 2015 guidance includes hedge positions as of June 30, 2015**.** Sensitivities include assumptions based on normalized historical basis differentials.
2. This guidance refers to certain non-GAAP measures such as cash flow and operating earnings. Cash flow is a non-GAAP measure defined as Cash from Operating Activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets. Operating Earnings is defined as Net Earnings excluding non-recurring or non-cash items that Management believes reduces the comparability of the Company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.
3. Excludes long-term incentives and restructuring charges.
4. Based on year-end 2014 reserves and reflects year to date June impairments and year to date acquisition and divestiture transactions.

2015F ENCANA CORPORATE GUIDANCE

US$, U.S. GAAP

July 24, 2015

Advisory

Certain statements contained in this document are forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements in this document include, but are not limited to:

- estimates of cash flow, including per share amounts
- natural gas, oil and natural gas liquids production
- capital investment
- operating costs
- sensitivities on price and their impact on cash flow and operating earnings and assumptions regarding oil, natural gas and natural gas liquids prices and foreign exchange rates.
- projections regarding funding of 2015 capital program and anticipated dividends

Readers are cautioned upon unduly relying on forward-looking statements as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, these statements involve numerous assumptions, known and unknown risks and uncertainties and other factors, which can contribute to the possibility that such statements will not occur or which may cause the actual performance and financial results of the Company to differ materially from those expressed or implied by such statements. These assumptions include, but are not limited:

- assumptions based upon the Company's current guidance
- effectiveness of the Company's resource play hub model to drive productivity and efficiencies
- results from innovations
- availability of attractive hedge contracts
- expectations and projections made in light of, and generally consistent with, Encana's historical experience and its perception of historical trends, including with respect to the pace of technological development, the benefits achieved and general industry expectations

Risks and uncertainties that may affect the operations and development of our business include, but are not limited to: the ability to generate sufficient cash flow to meet the Company's obligations; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability of dividends to be paid; the timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; risk and effect of a downgrade in credit rating, including access to capital markets; fluctuations in currency and interest rates; assumptions based upon the Company's 2015 corporate guidance; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; the Company's ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; risks associated with past and future divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties impacting Encana's business as described from time to time in Encana's most recent MD&A, financial statements, Annual Information Form and Form 40-F, as filed on SEDAR and EDGAR.

Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the assumptions, risks and uncertainties referenced above are not exhaustive. The forward-looking statements contained in this document are made as of the date of this document and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by these cautionary statements.

In this document, certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (Mcf) to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head. Given that the value ratio based on the current price of natural gas as compared to oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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