BARCLAYS CEO ENERGY-POWER CONFERENCE

SEPTEMBER 8, 2016

Roger W. Jenkins

PRESIDENT & CHIEF EXECUTIVE OFFICER

MURPHY OIL CORPORATION

Cautionary Statement

Cautionary Note to U.S. Investors – The United States Securities and Exchange Commission permits oil and natural gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves. We may use certain terms in this presentation, such as “resource”, “gross resource”, “recoverable resource”, “net risked P_{MEAN} resource”, “recoverable oil”, “resource base”, “EUR or estimated ultimate recovery” and similar terms that the SEC’s rules strictly prohibit us from including in filings with the SEC. Investors are urged to consider closely the oil and natural gas disclosures in Murphy’s 2015 Annual Report on Form 10-K on file with the SEC.

Forward-Looking Statements – This presentation contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. Words such as “targets”, “expectations”, “plans”, “forecasts”, “projections”, and other comparable terminology often identify forward-looking statements. These statements, which express management’s current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause one or more of the events forecasted in this presentation not to occur include, but are not limited to, a deterioration in the business or prospects of Murphy, adverse developments in Murphy’s markets, or adverse developments in the U.S. or global capital markets, credit markets or economies generally. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, political and regulatory instability, and uncontrollable natural hazards. For further discussion of risk factors, see Murphy’s 2015 Annual Report on Form 10-K on file with the U.S. Securities and Exchange Commission. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

Agenda

01 Business Update

02 Portfolio Review

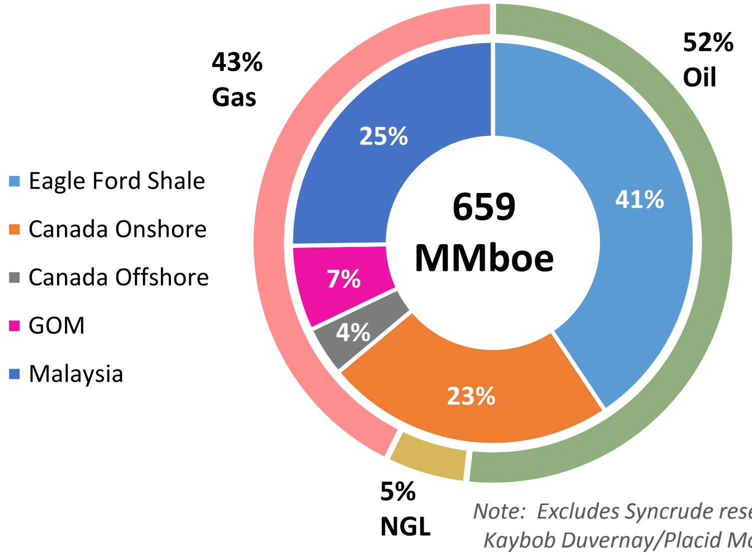
03 Takeaways

Murphy At a Glance

- Long Corporate History, IPO in 1956
- Global, Diversified Asset Base Provides Balance
- Stable Cash Flows from Long-Lived Conventional Reserves
- Strong Onshore Growth Opportunities from Leading North American Unconventional Resource Plays
- Strong Balance Sheet & Prudent Financial Management
- Low Leverage with Ample Liquidity and Manageable Debt Maturities
- Proven Safety Track Record Across All Operations

KEY AREAS OF PRODUCTION

2015 Proved Reserves



Note: Excludes Syncrude reserves of 115 MMboe
Kaybob Duvernay/Placid Montney closed 2Q 16

Recalibrating the Company

Portfolio Repositioning

- Streamlining NA Onshore Portfolio
- Low Cost Entry into Kaybob Duvernay & Placid Montney
- Monetization of Syncrude & Canadian Midstream Assets

Stabilize Production at Lower Capex

- Significant Capex Reduction While Maintaining Production Guidance
- Capex Allocation Focused on High Returning Areas

Cost Reductions

- 14% LOE Reductions from 2014 Levels
- 32% G&A Reductions from 2014
- 40% Staff Reductions from 2015

Shareholder Focus

- Adjusted Dividend While Maintaining Top Quartile Yield
- No Equity Issuance in 2015 – 2016 Oil Collapse

Preserve Balance Sheet

- Renegotiated Unsecured Credit Facility
- Ample Liquidity for Lower for Longer Pricing
- $550 MM Bond Issuance

Portfolio Repositioning

Divested Non-Core Assets	Entered Into Strategic JV

MONTNEY MIDSTREAM – TOP OF CYCLE

- C$539 MM Proceeds from Sale Before Closing Adjustments
- Proceeds Allocated to Portfolio Enhancements and Debt Repayment
- 20 Year Fee Structure

SYNCRUDE – MID CYCLE

- C$937 MM Proceeds from Sale Before Closing Adjustments
- Repaid Revolver in its Entirety on June 30, 2016

KAYBOB DUVERNAY & PLACID MONTNEY BOTTOM OF CYCLE

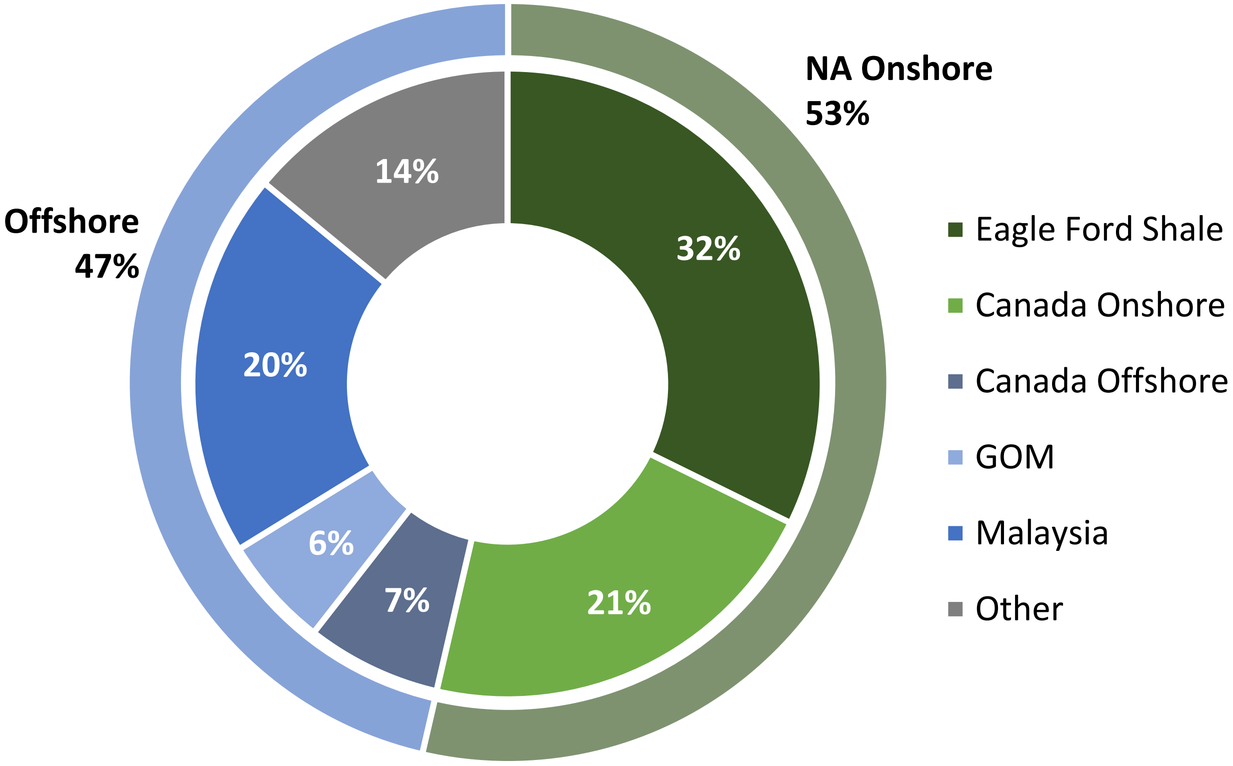
- C$267 MM Paid
- C$219 MM Carry Over 4 to 5 Years
- 70% WI (Operated) in Kaybob Duvernay
  - 500 – 600 Gross Locations
  - Upside with Well Optimization & Down-spacing
- 30% WI (Non-op) in Placid Montney
  - 100 – 200 Gross Locations
  - Upside with Well Optimization & Down-spacing

$960 MM Net Proceeds Recorded in 2Q 2016 Through Non-Core Asset Sales

Note: USD/CAD rate of 0.7919

Stabilize Production at Lower Capex

2016 Total Capex, $620 Million



Field Development & Development Drilling
~77%

$620 MM 2016 Capex

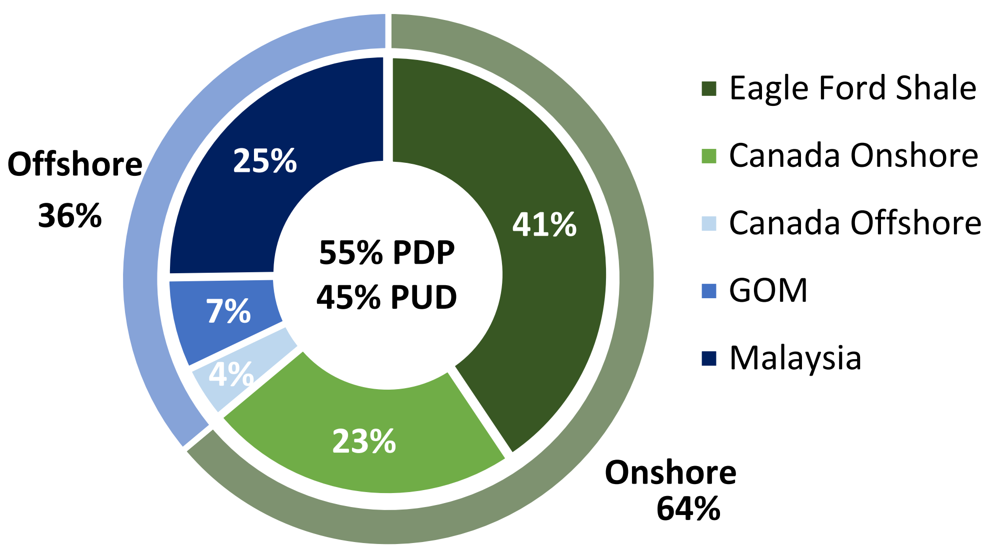
- Excluding $207 MM Associated with Acquisition of Kaybob Duvernay & Placid Montney JV

2016 Production

- 3Q 16 Guidance 167.5 – 169.5 Mboepd
- FY 16 Guidance 173 – 177 Mboepd

Consistent Reserve Replacement

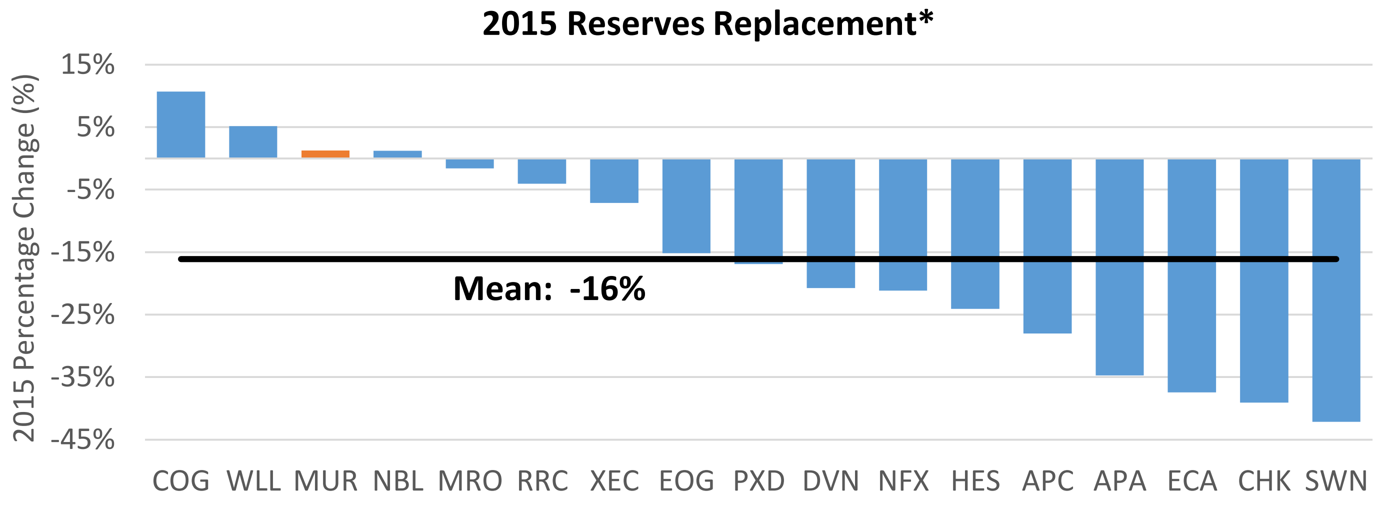
2015 Proved Reserves
659 MMboe*

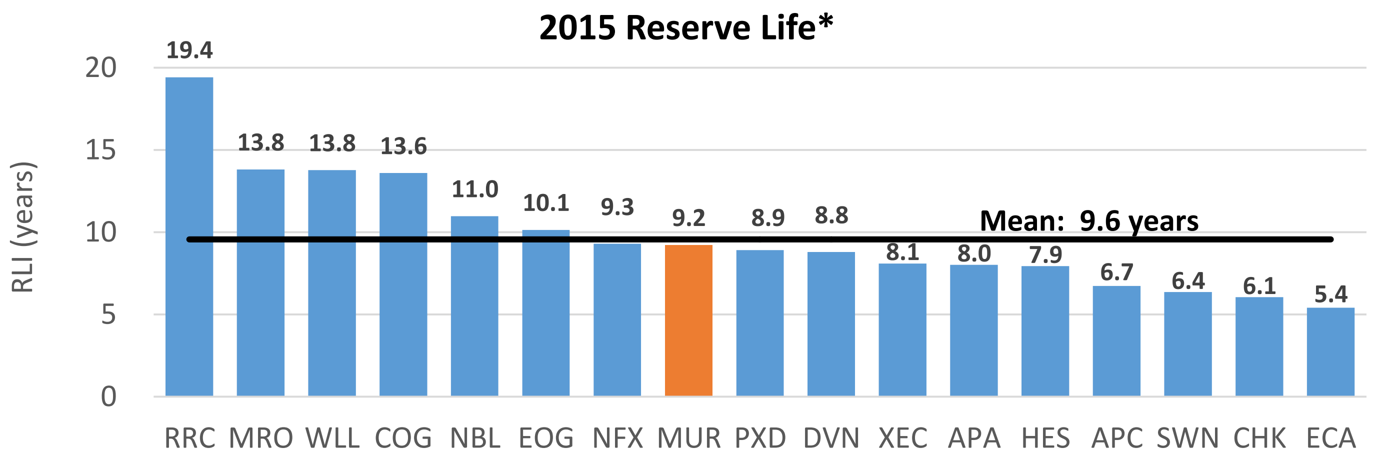


62% Liquids & Oil-Indexed Gas**

- 5 Year Reserve Life Increase of ~45%
- 5 Year Average Replacement >180%
- 9% CAGR Reserve Growth 2010 – 2015

**Excludes Syncrude reserves of 115 MMboe*
Kaybob Duvernay/Placid Montney closed 2Q 16
***57% liquid reserves, 5% oil-indexed gas*

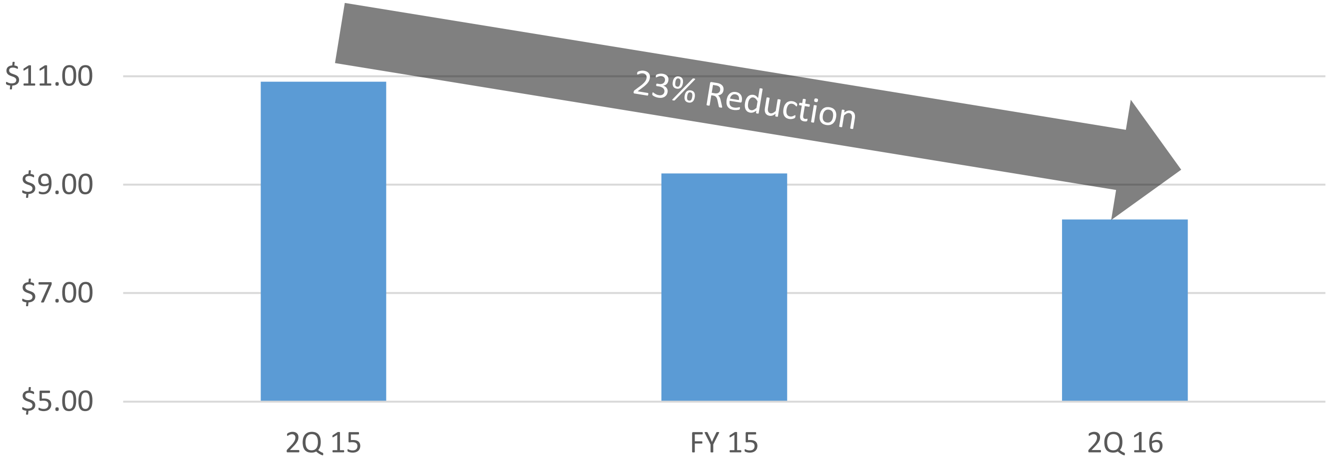




Source: Bloomberg, Company 10-K Reports
**Excludes Syncrude Reserves*

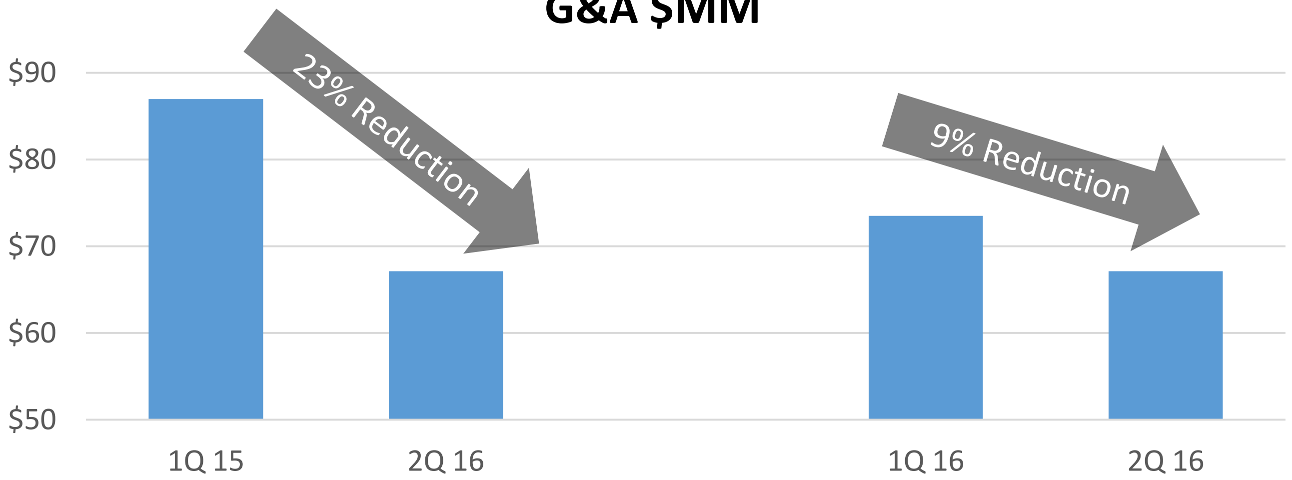
Cost Reductions

Lease Operating Expense* $/boe



**Excludes both Syncrude and Severance & Ad Valorem Taxes*

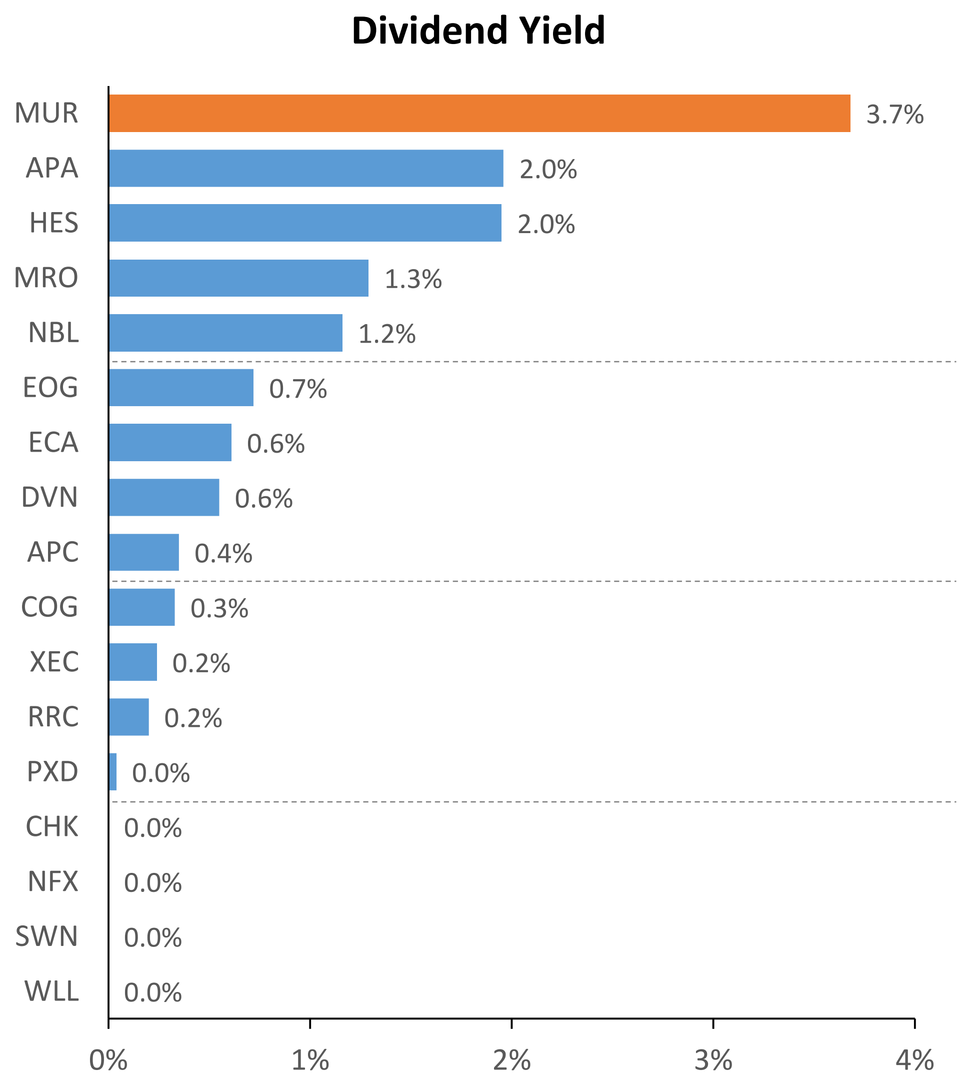
G&A $MM



Focusing on Cost Reductions 2Q 16

- Reduced LOE Costs 23% Q-O-Q
- Reduced Recurring G&A Costs by 23% Since 2015
  - Continuous Review and Removal of Unnecessary Costs in All Categories
  - Key Resources Retained When Capex Ramps-up

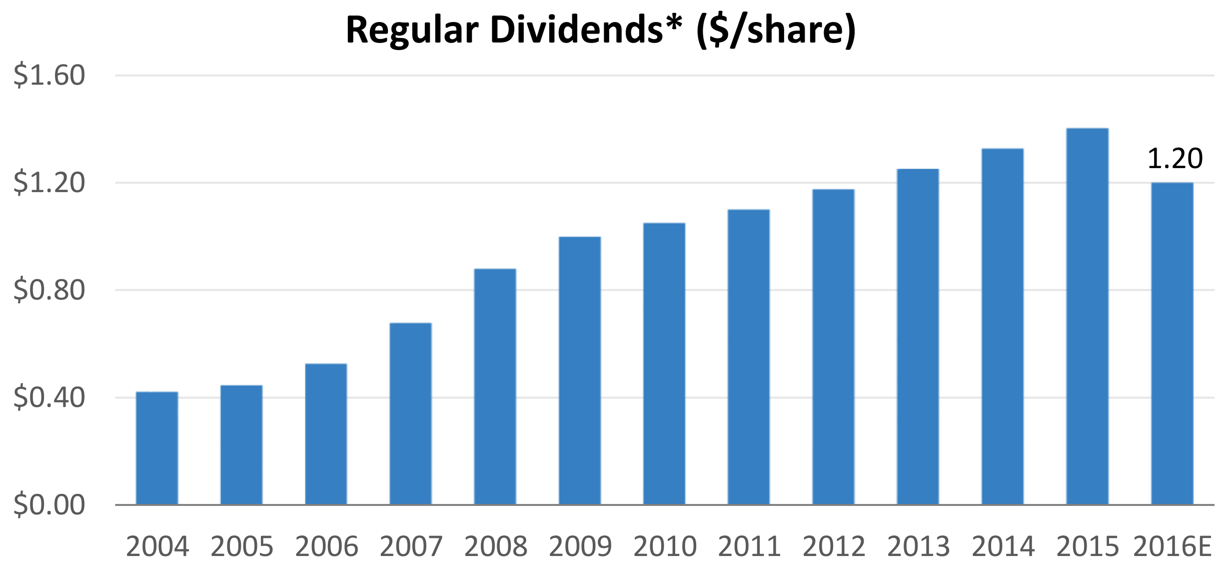
Shareholder Focus



Source: Bloomberg
Based on close prices from 9/2/16

Committed to the Dividend

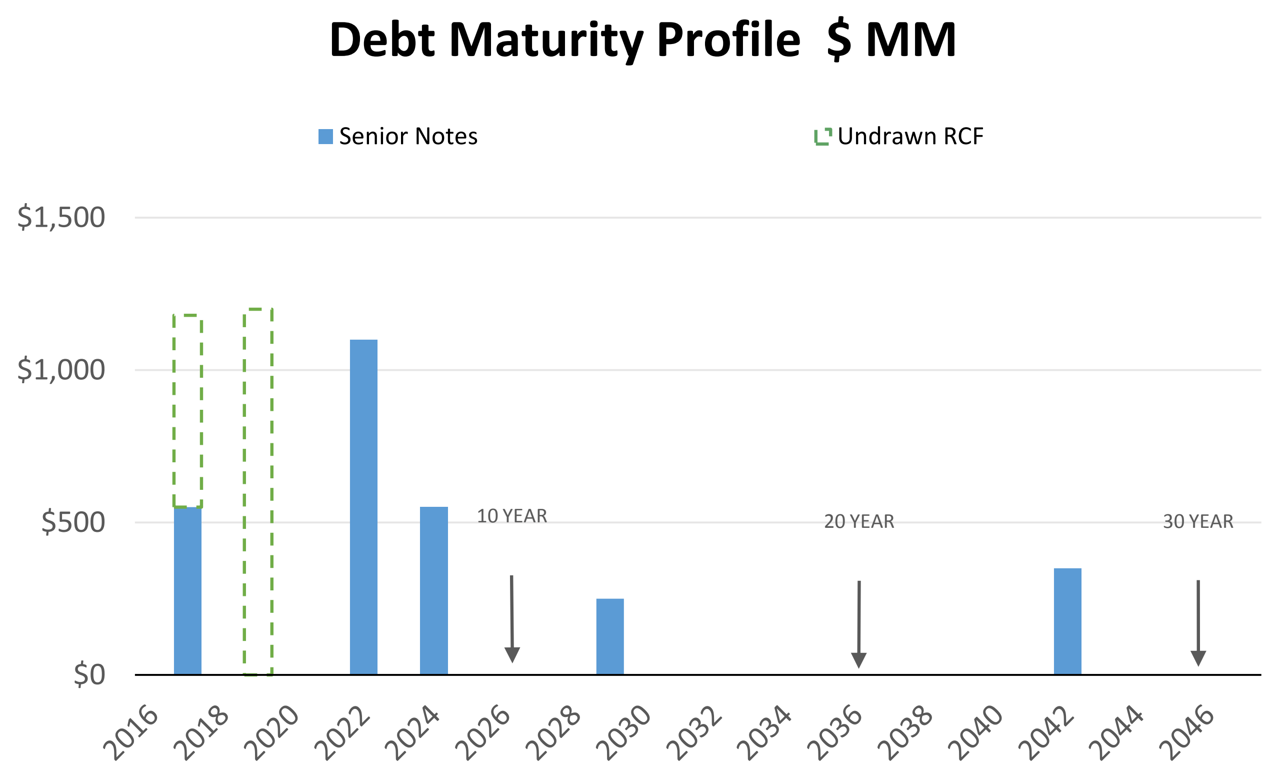
- Top Quartile Yield Among Peer Group
- Recalibrated Dividend in 3Q 16
- 9% CAGR Over the Last 11 Years
- Current Annualized Dividend of $1.00/share



** Does not include special dividends or Spin effects*

Preserve Balance Sheet

- New $1.2 BN Credit Facility with 3 Year Maturity
- $630 MM of Existing Non-Extending Commitments Expire June 2017
- Zero Drawn on Credit Facilities
- $935 MM of Cash and Liquid Invested Cash*
- Issued $550 MM, 8 Year Senior Notes Providing Additional Liquidity to Repay 2017 Senior Notes



** June 30, 2016 balances adjusted for net cash proceeds of bond issuance*

PORTFOLIO REVIEW

North America Onshore Operations

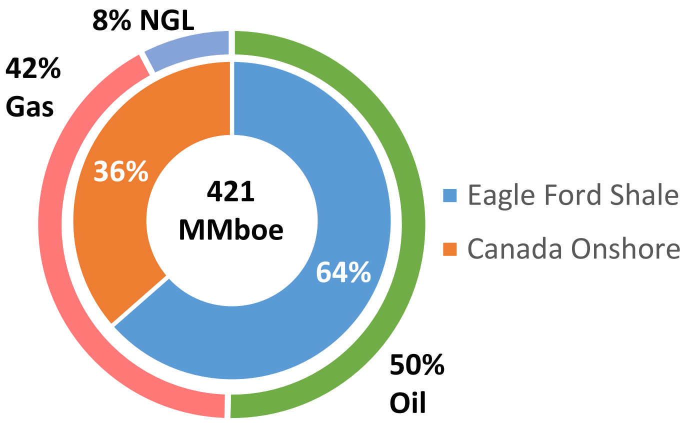
Canada Onshore

- Kaybob Duvernay (Operated)
- Placid Montney (Non-Op)
- Tupper Montney (Operated)

US Onshore

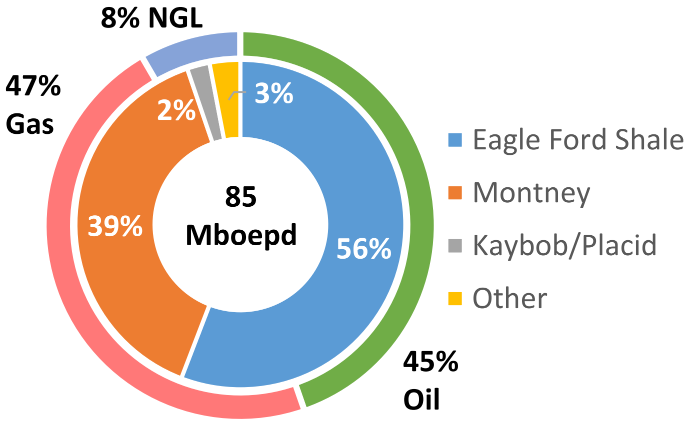
- Eagle Ford Shale (Operated)
    - Karnes
    - Tilden/N. Tilden
    - Catarina

2015 Proved Reserves*



*Excludes Syncrude Reserves of 115 MMboe
Kaybob Duvernay/Placid Montney Closed 2Q 16

2Q 2016 Production*



*Excludes Syncrude Production of 3.1 Mboepd
Kaybob Duvernay/Placid Montney Closed 2Q 16

US Eagle Ford Shale – Oil Weighted & Ground Floor Entry

Remaining Resource Potential 800+ MMboe

Karnes

- ~11,200 Net Acres at 40 Acre Spacing
- 240 Wells Drilled*
- 600 Mboe Estimated Per Well EUR
- Austin Chalk – Resource Upside

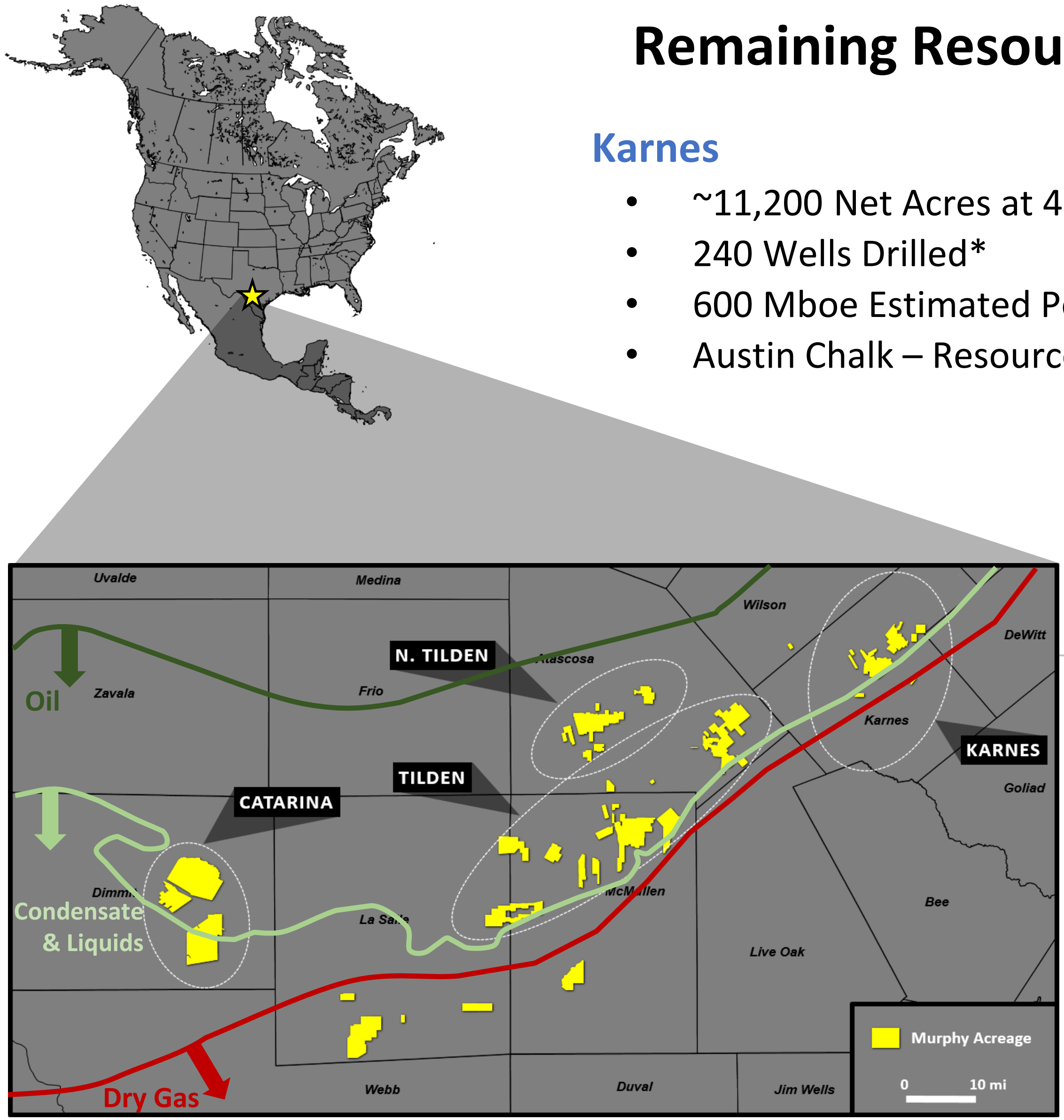
Tilden/N. Tilden

- ~77,400 Net Acres at 40/80 Acre Spacing
- 415 Wells Drilled*
- 360 – 435 Mboe Estimated Per Well EUR

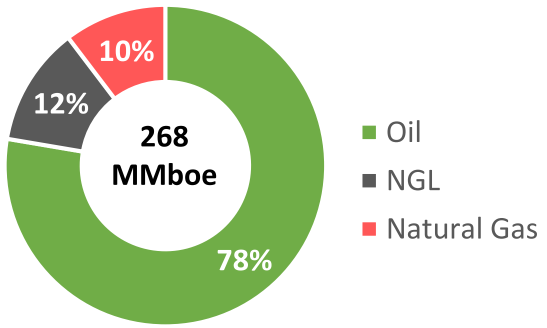
Catarina

- ~48,000 Net Acres at 80 Acre Spacing
- 160 Wells Drilled*
- 420 – 625 Mboe Estimated Per Well EUR
- Austin Chalk – Resource Upside

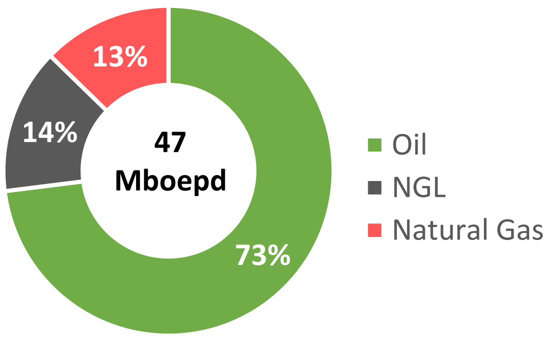
*As of June 30, 2016



2015 Proved Reserves



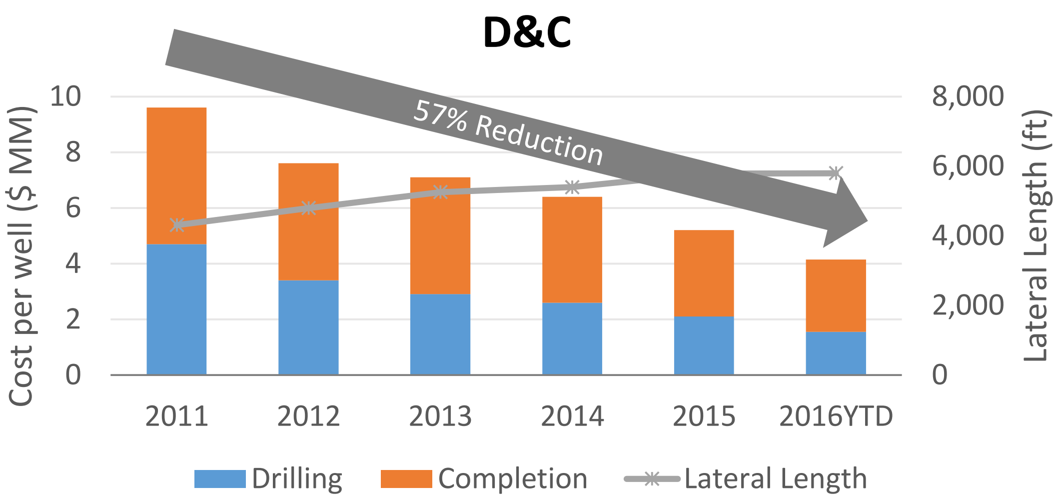
2Q 16 Production

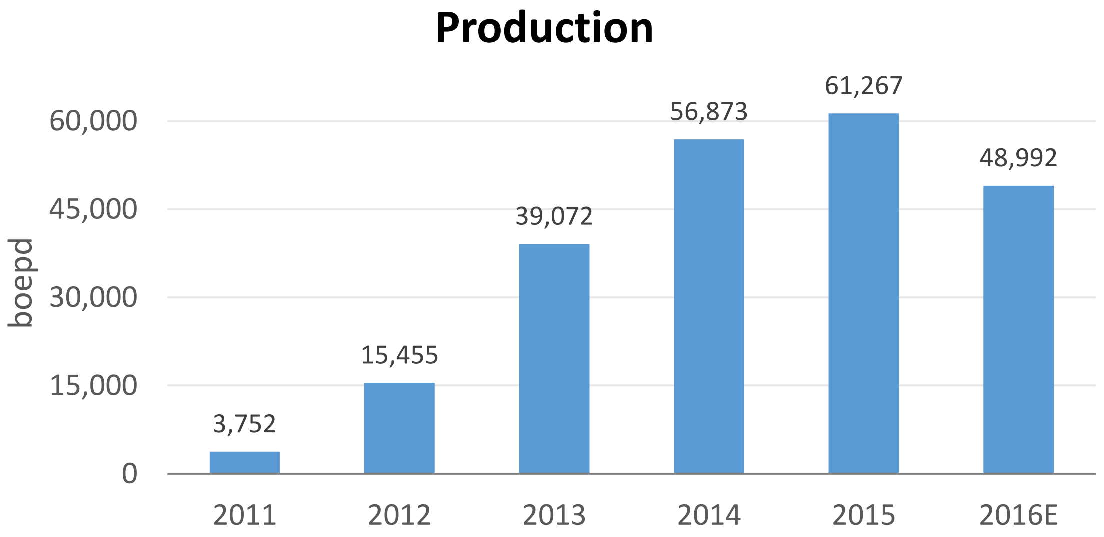


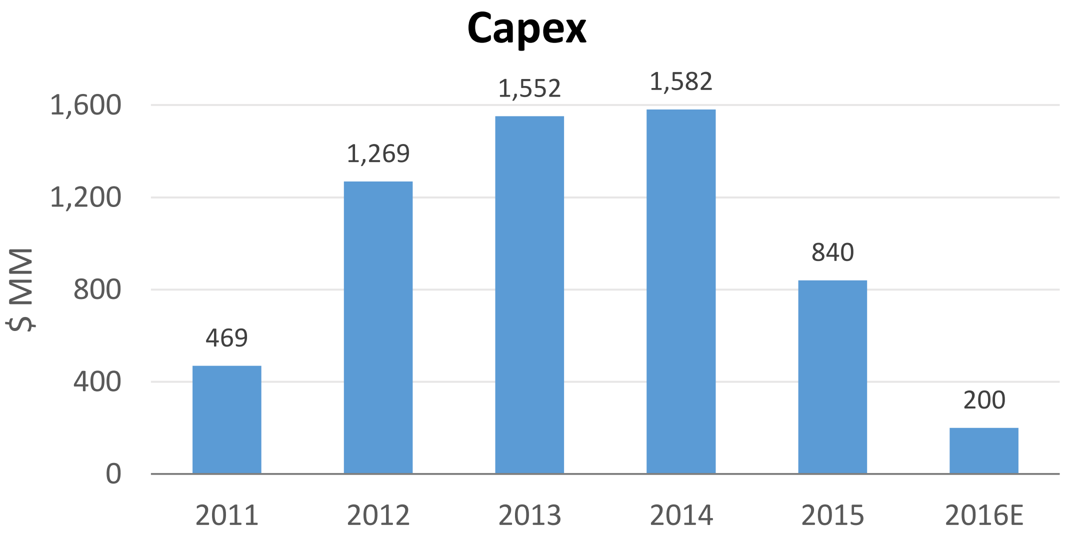
Note: ~45° API Gravity

Eagle Ford Shale Highlights

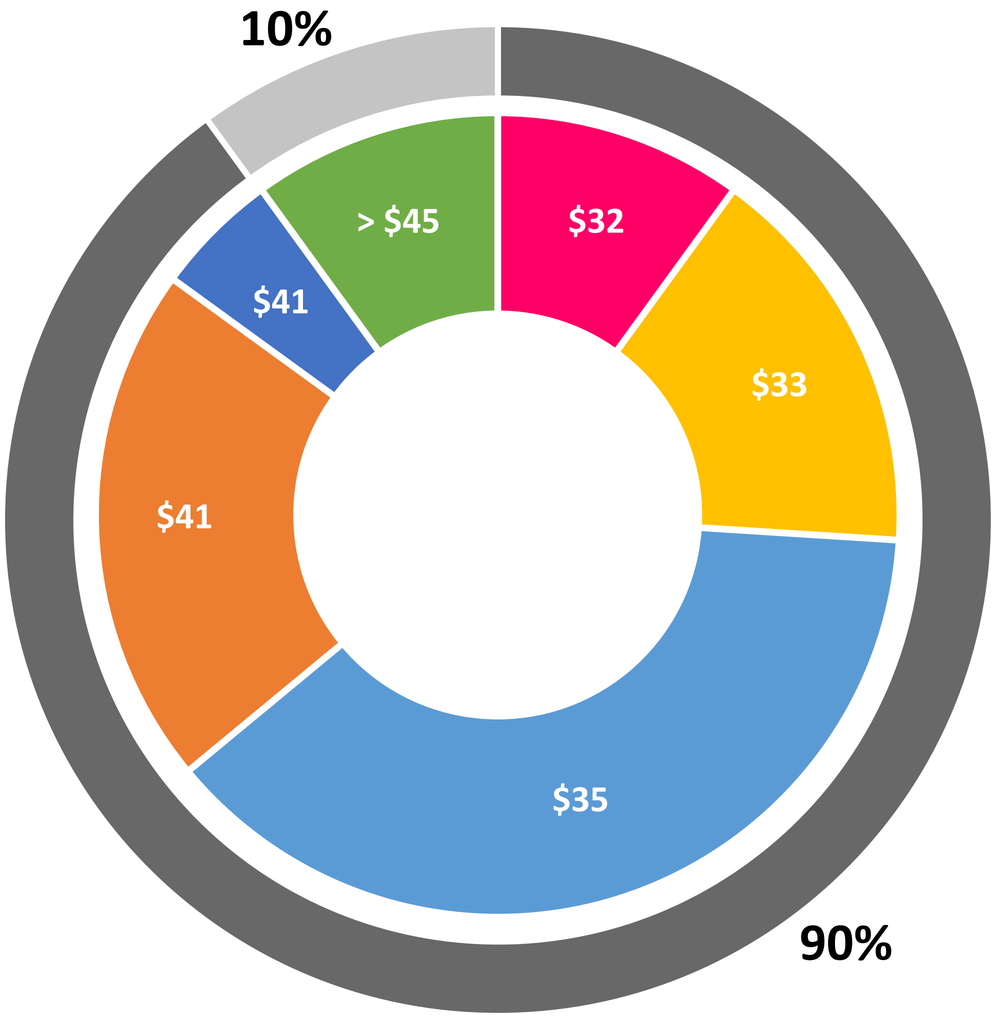
2016 YTD	
EUR	385 – 600 Mboe
D&C Cost	$4.2 MM
D&C Cost Per Lateral ft	$102 (Drilling); $480 (Completions)
Lateral Length	~5,000 – 8,700 ft







Eagle Ford Shale Break-Even Oil Price by Area



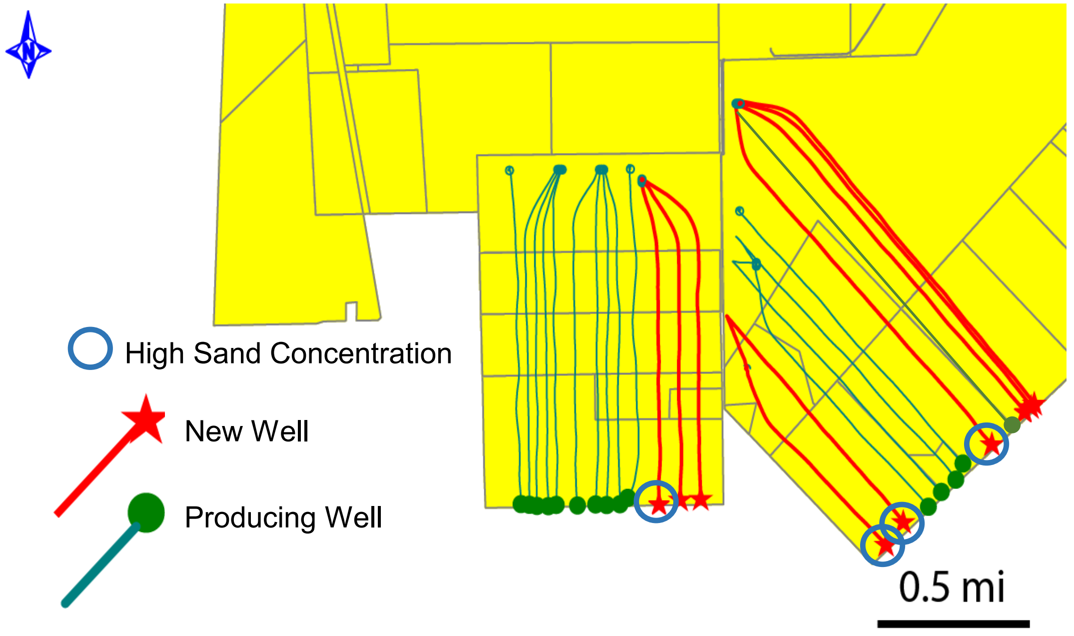
- **90% of Remaining Locations Have WTI Break-Even Cost of $41/bbl or Less**
- **Focused on Higher Returning Locations**

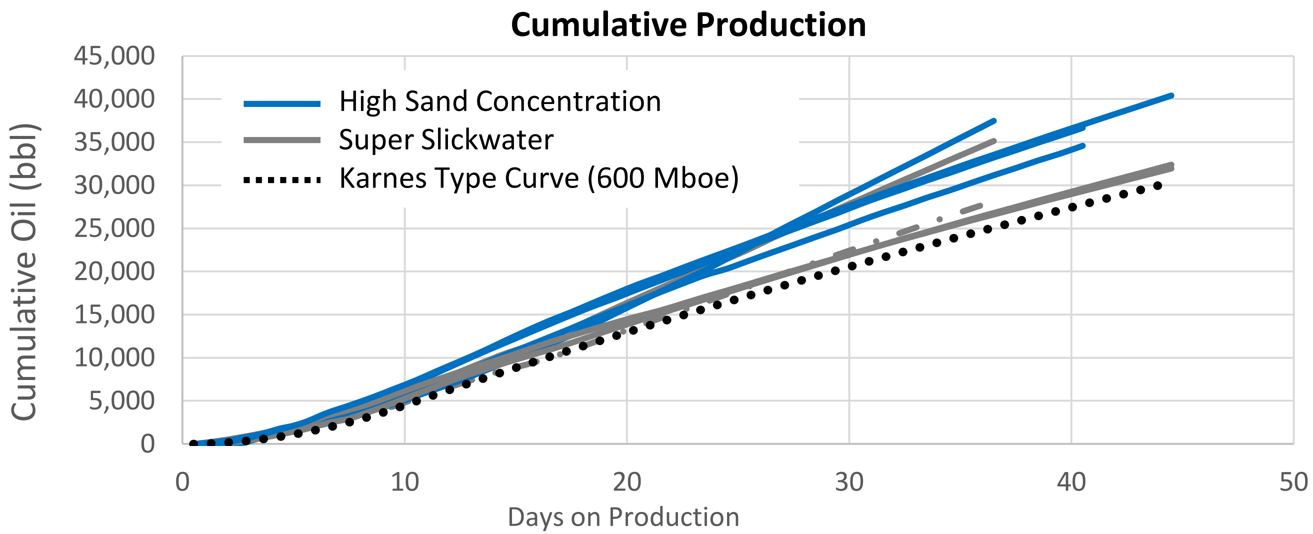
Note: Eagle Ford locations reflect YE15 inventory assumptions
Includes 350' Lower EFS infills, Upper EFS and Austin Chalk on wider spacing
Gas Price HH Posted $2.34/MMBTU, NGL=$13.17/bbl

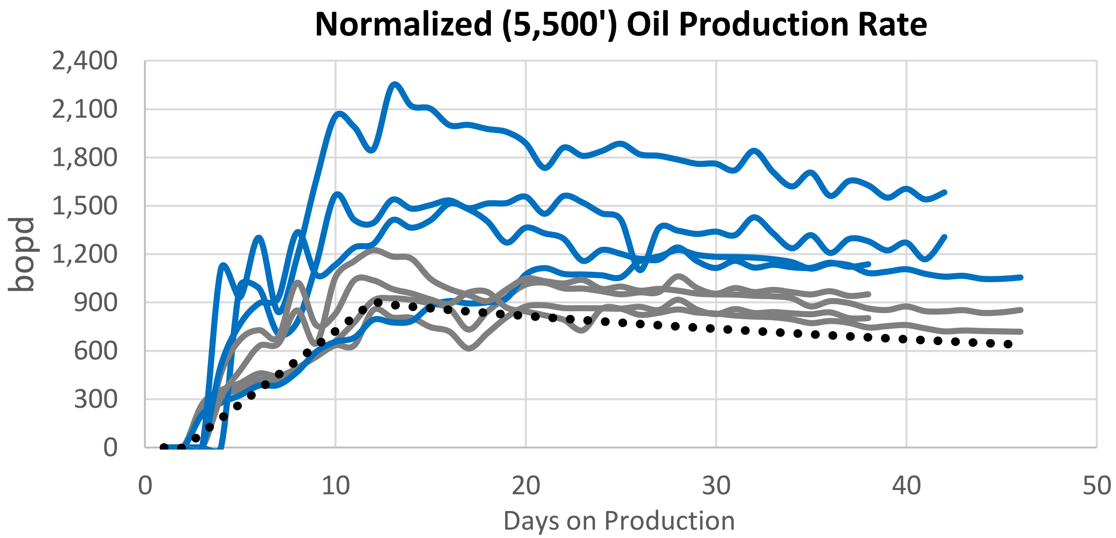
Eagle Ford Shale – High Concentration Sand Fracs

Successful High Concentration Sand Fracs in Karnes

- IP Rates ~20% Higher than Recent Super Slickwater
- IP Rates ~30% Higher than Early Offset Wells
- Upper EFS Well Outperforming 600 Mboe Karnes Type Curve
- Less Offset Frac Impact to Early Offset Wells, Possible Sustained Uplift







Austin Chalk Update

Future Plans

Karnes

- Janysek A 1H Online September 2016
- Plan to Drill 3 Austin Chalk Wells in 4Q 16 (Online 1Q 17)
- Plan to Drill 4 Austin Chalk Wells in 2017

Catarina

- Lopez Unit A 1H Online September 2016
- Plan to Drill 3 Austin Chalk Wells in 2017

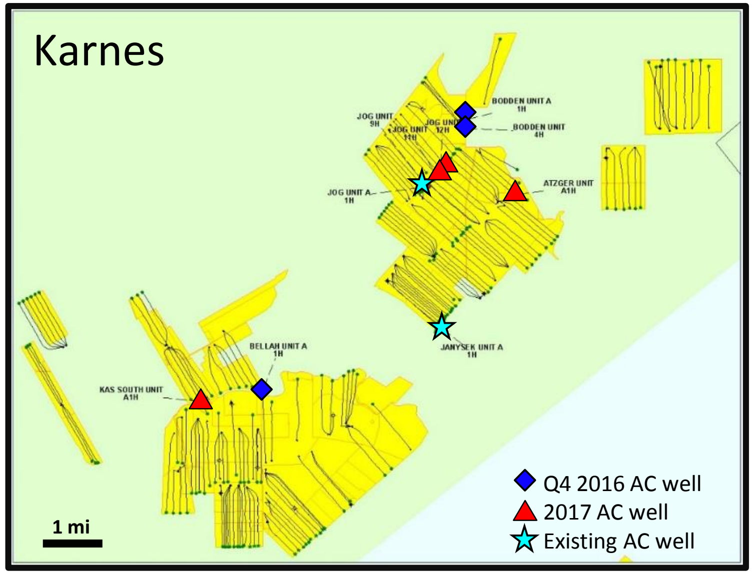
Current Resource Estimate

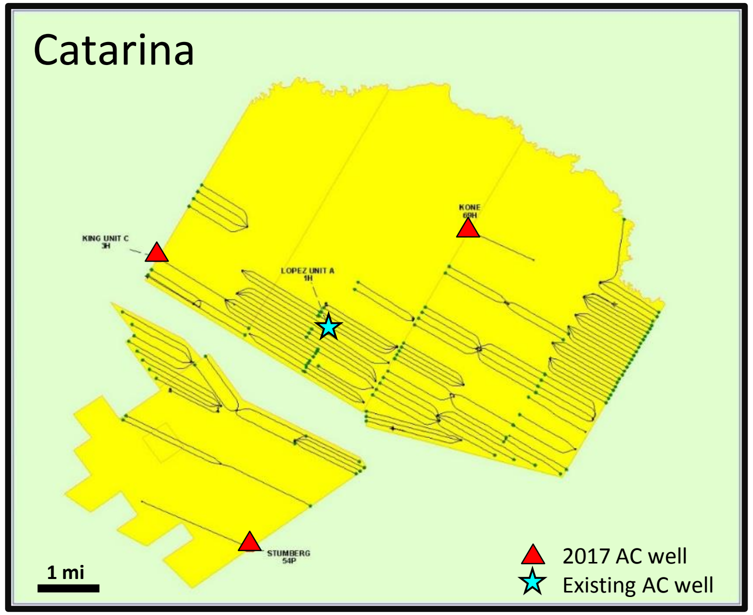
Karnes

- 115 Locations at 80 Acre Spacing
- 30 MMboe Net Resource Using 450 Mboe Estimated Type Curve EUR

Catarina

- 150 Locations at 100 Acre Spacing
- 50 MMboe Net Resource Using 415 Mboe Estimated Type Curve EUR





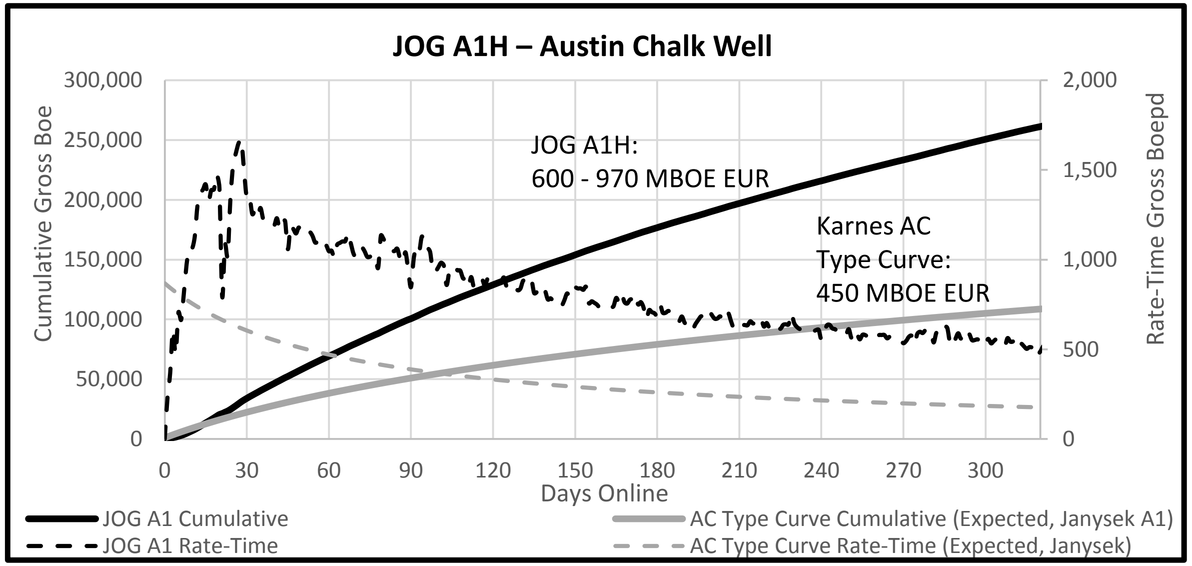
Recent Austin Chalk and Upper EFS Results

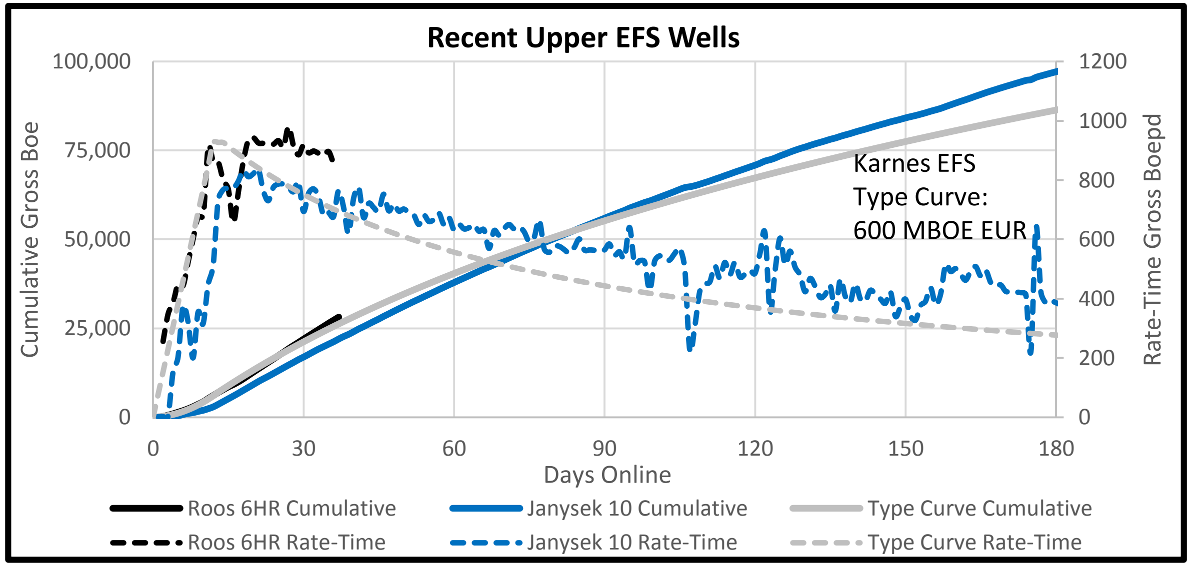
Austin Chalk Well Exceeding EFS Type Curve

- JOG Unit A 1H – On Production 4Q 15
- Gross IP 1,648 boepd, Cum 261 Mboe
- Estimated 600 – 970 Mboe EUR

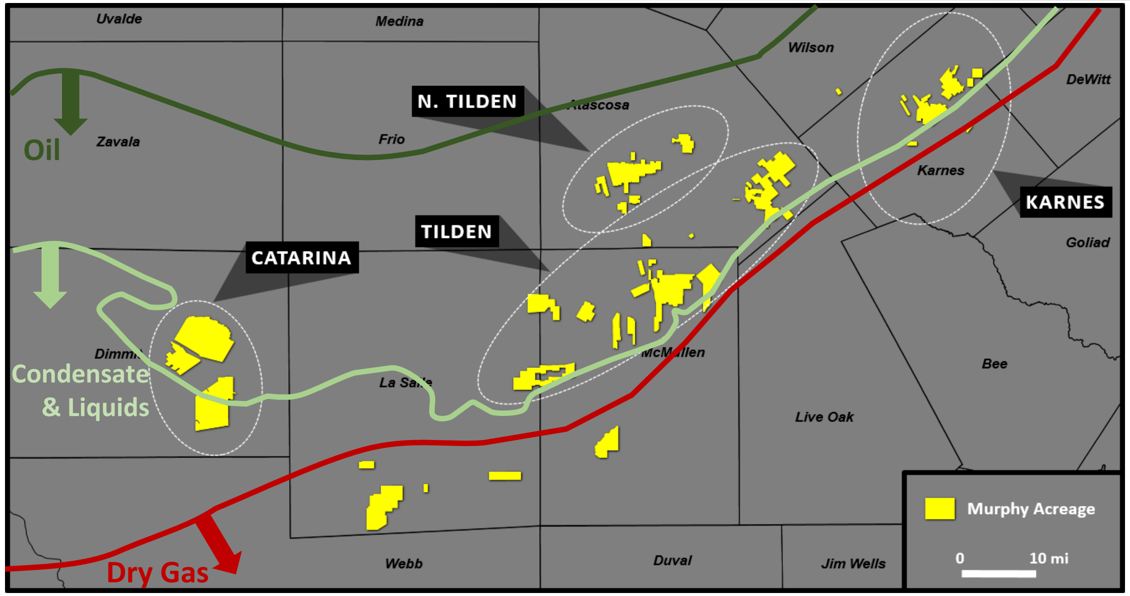
Upper EFS Wells Initial Results Promising

- Evaluating & Defining Areas for Potential Co-Development
- Optimizing Well Spacing & High Concentration Completions for Staggered Potential in 3 Zones
  - Austin Chalk, Upper & Lower EFS





Eagle Ford Shale – Running Room

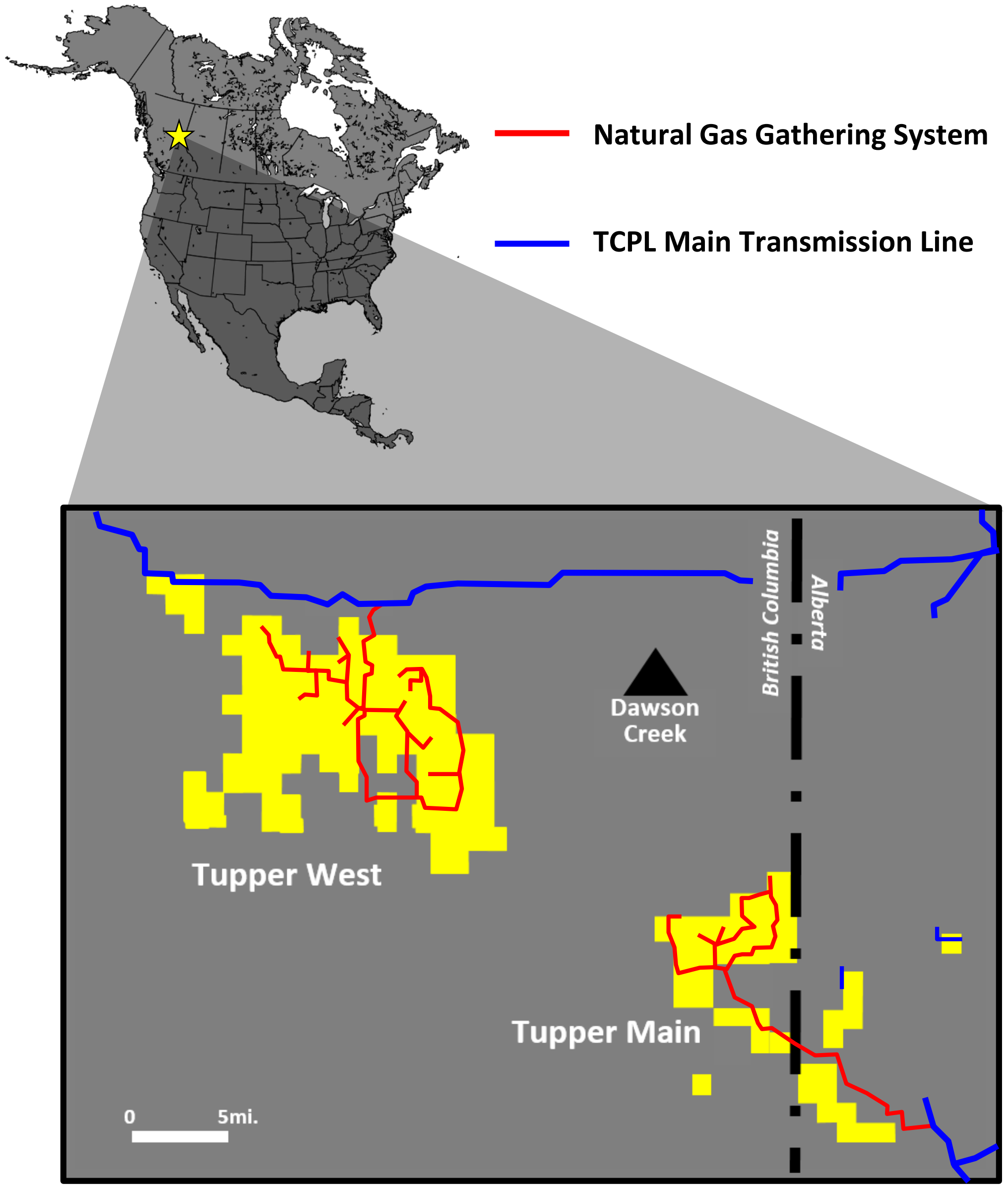


Significant Multi-Year Inventory with Stacked Pay Potential Upside

- 800+ MMboe Proved & Net Recoverable Resource
- $2,055 per Acre Early Entrant

Area	Net Acres	PDP Wells	Lower EFS Locations Remaining	Upper EFS Locations Remaining	Austin Chalk Locations Remaining	Acre Spacing			Total Well Count (Unrisked)
						Lower EFS	Upper EFS	Austin Chalk	
Karnes	11,222	235	61	138	114	40	40	80	548
Tilden	60,076	370	468	115	100	40 – 60	60	60	1,053
North Tilden	17,306	29	64	0	0	80	–	–	93
Catarina	47,846	145	482	380	150	50	70	100	1,157
Nueces	10,151	13	0	0	0	–	–	–	13
Total	**146,601**	**792**	**1,075**	**633**	**364**				**2,864**

Tupper Montney Overview



Tupper Main

- ~30,000 Net Acres
- 110 MMcfd Plant Capacity (Gross)
- 20 Year Processing Arrangement with Enbridge
- 118 Wells Drilled*
- 2Q 16 Net Production: 79 MMcfepd

Tupper West

- ~72,000 Net Acres
- 210 MMcfd Plant Capacity (Gross)
- 20 Year Processing Arrangement with Enbridge
- 133 Wells Drilled*
- 2Q 16 Net Production: 119 MMcfepd

Reduced Drilling and Completing Costs by 34% Since 2014 with 2016 YTD Costs Below $3.8 MM While Increasing EURs by ~90% Over Same Time Period

Full Cycle Break-Even Prices ~C$2.10 / MCF (C$ AECO)**

- Focused on Hedging Portion of 2017 – 2020 Production at ~C$3.00 / MCF

Long Term Growth

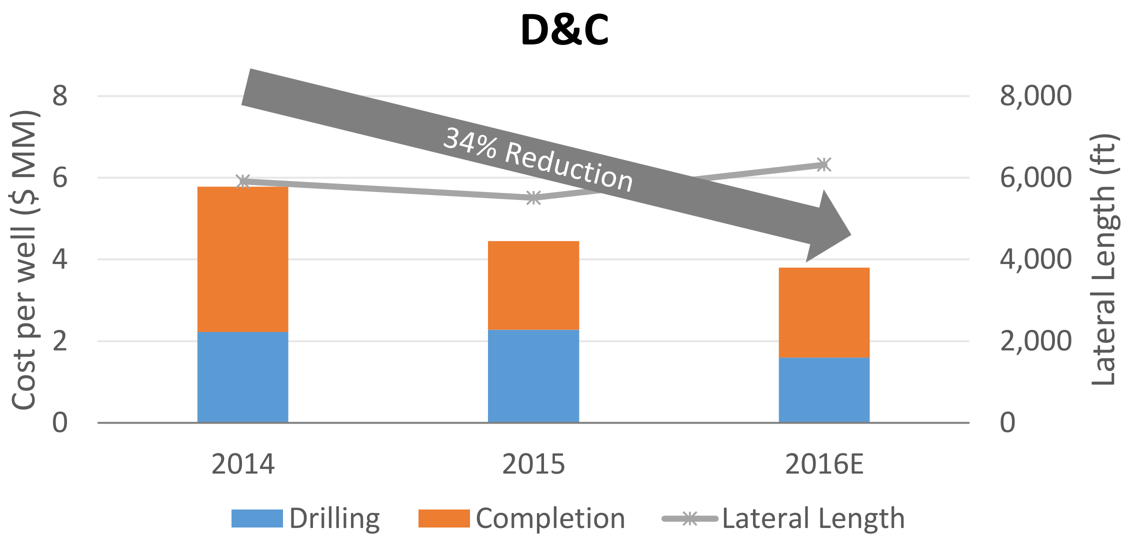
- ~900 Gross Locations
  - 140 Acre Spacing
- Down-spacing Provides 1,200 Additional Locations
- 14 TCF Net Resource
- 28 TCF Original Gas in Place (OGIP)

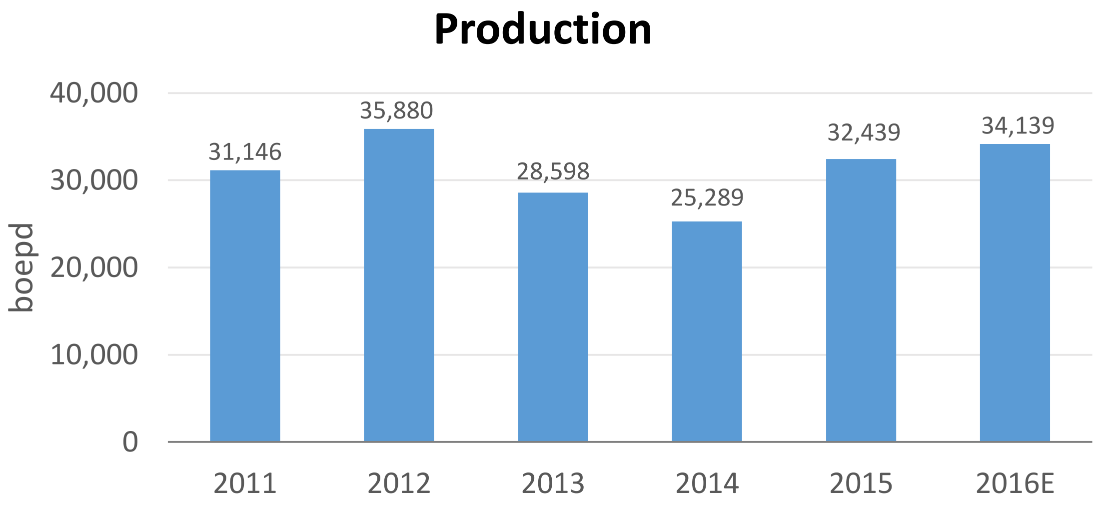
**As of June 30, 2016*

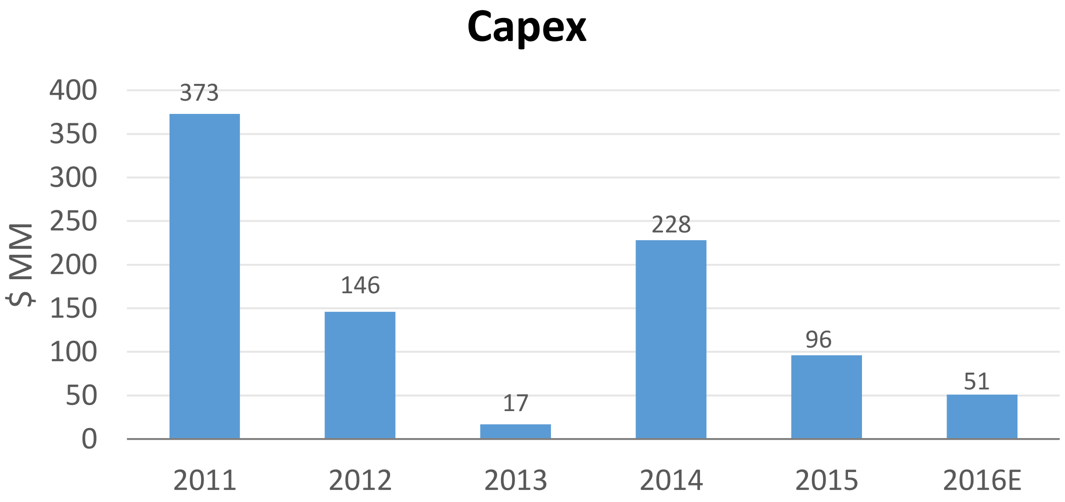
*** Full cycle economics which include land acquisition, G&A, and Opex (including Enbridge fee)*

Tupper Montney Highlights

2016 YTD	
EUR	10 – 14 BCFE
D&C Cost	$3.8 – 4.2 MM
D&C Cost Per Lateral ft	$97 (Drilling); $350 (Completions)
Lateral Length	~5,000 – 9,000 ft

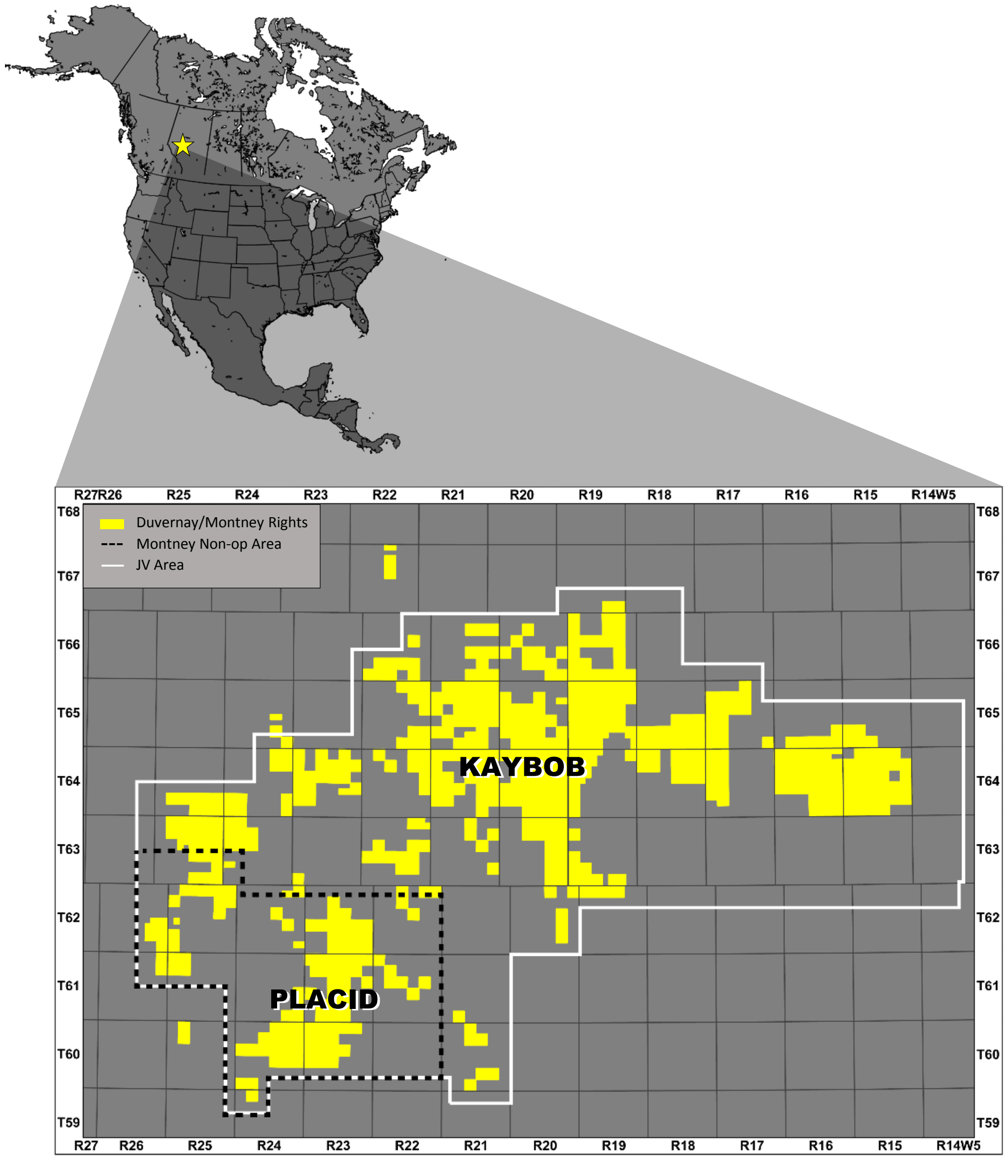






Note: 2011 Capex Excludes $195 MM for Tupper West Plant and Gas Gathering System (GGS)

Kaybob Duvernay & Placid Montney



Kaybob Duvernay

- 70% WI, Operatorship
- 232,000 Gross Acres (200,000 Currently Prospective)
- 3Q 16 Estimated Production: ~2,800 boepd
- 500 – 700 Mboe Estimated Per Well EUR (55 – 80% Liquids)
- Area Includes 247,000 Gross Acres of Overlying Conventional Montney Rights

Placid Montney

- 30% WI, Non-Operated
- 60,000 Gross Acres (21,000 Currently Prospective)
- 3Q 16 Estimated Production: ~800 boepd
- 750 Mboe Estimated Per Well EUR (30 – 40% Liquids)

Ownership in Local Infrastructure with Ample Capacity

Low Entry Cost – Top Quartile Field Life F&D

Multi-Year Running Room with Resource Upside

Long Term Condensate Demand from Regional Heavy Oil Projects

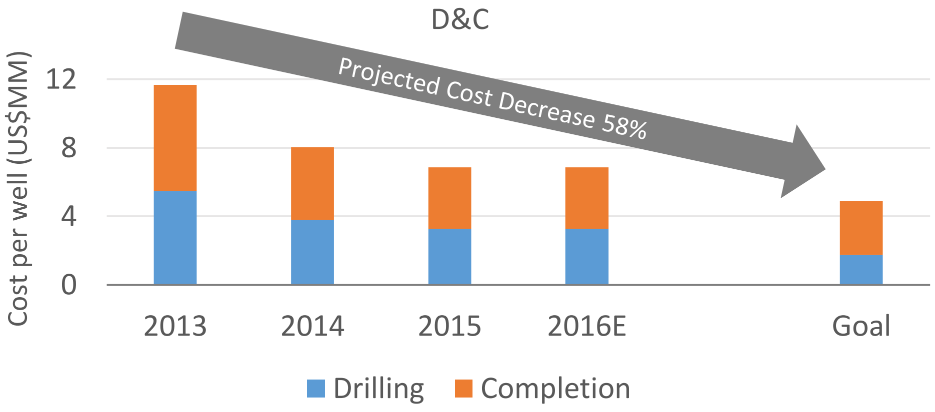
Established In-House Expertise & Preferred Partner

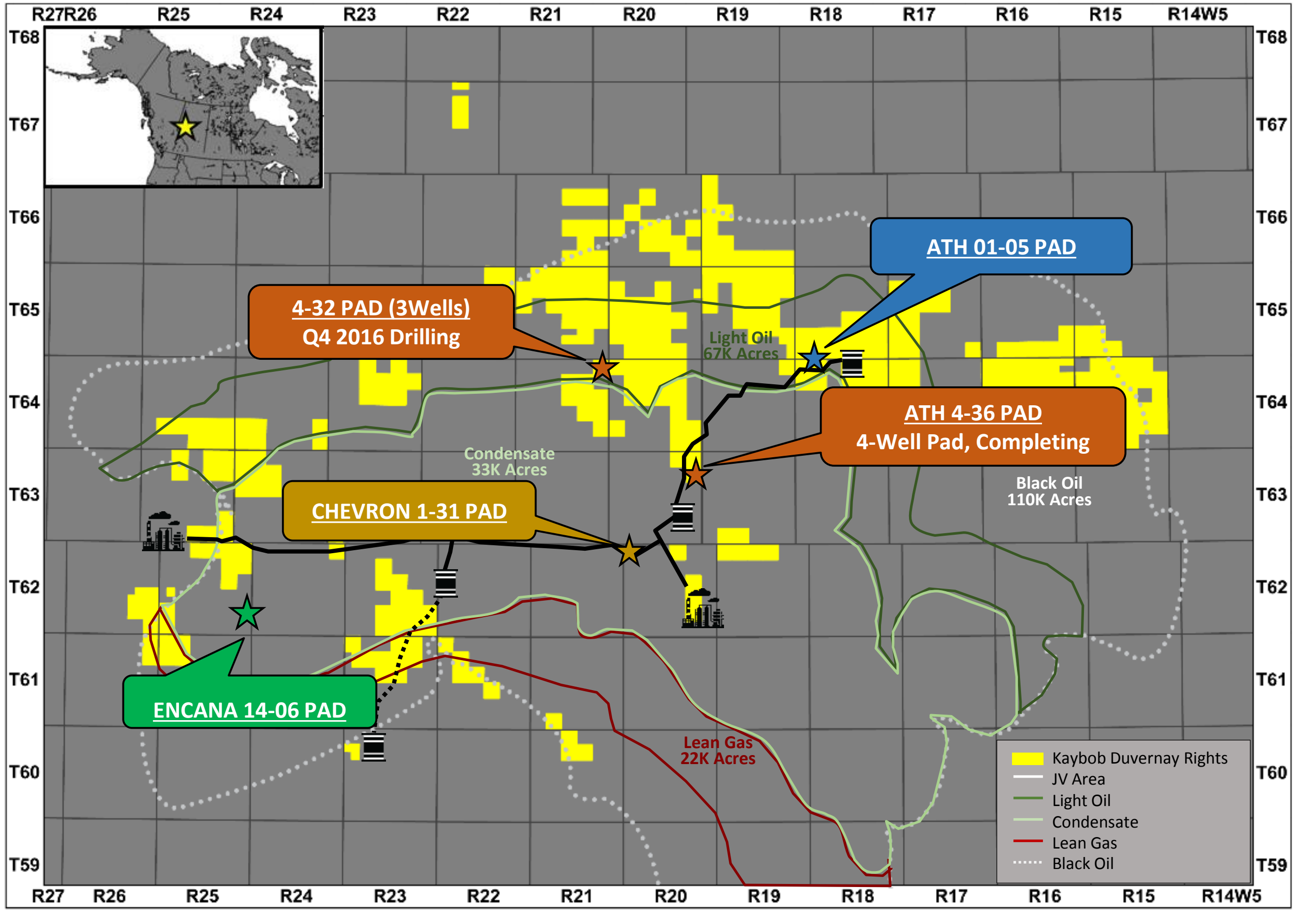
Kaybob Duvernay Activity Update

2H 2016 Plans
- 2 Wells Drilled; 4 Wells On-Line

Long Term Growth
- 500 – 600 Gross Locations
  - Condensate – 160 Acre Spacing
  - Light Oil – 160 Acre Spacing
- 500+ Potential Down-spacing Upside
- 1,000+ in Untapped Black Oil – 160 Acre Spacing

Improved Results Provide Economic Upside
- Increasing Well EURs
- Optimizing Completion Techniques
  - Lateral Lengths Range from 4,500 – 9,000 ft
  - Increasing Sand Concentration 100% to 2,000 lb/ft
- Decreasing D&C Costs





Recent Production - 2016

★ 01-31 Pad (1 Well)
- Chevron 01-31 IP30: 674 boepd (157 BPM, 48% Liq)

★ 14-06 Pad (6 Wells)
- Encana 14-16 PAD IP60: 1700 boepd (166 BPM, 50% Liq) *(Avg per Well)*

★ 01-05 Pad (2 Wells)
- ATH /16-6 IP30: 460 boepd (649 BPM, 81% Liq)
- ATH 02/16-6 IP30: 677 boepd (633 BPM, 79% Liq)

★ 2016 Future MUR Drilling/Completions

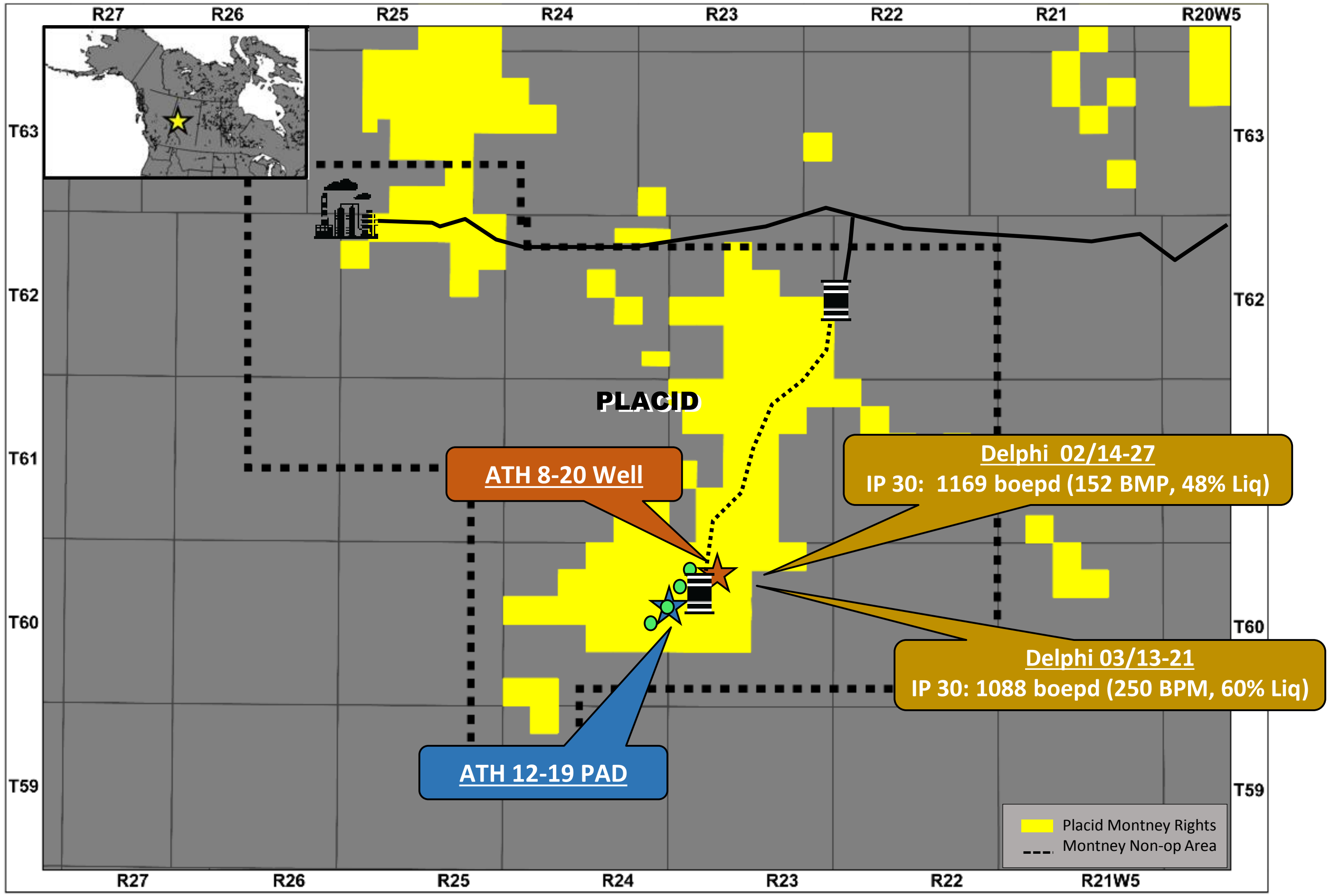
BPM (Barrels per mmcf)

Placid Montney Activity Update

2H 2016 Plans
- 12 Wells Drilled; 4 Wells On-Line

Long Term Growth
- 100 – 200 Gross Locations
  - 210 Acre spacing
- Potential Down-spacing Upside

Improved Results Provide Economic Upside
- Increasing Well EURs
- Optimizing Completion Techniques
- Decreasing D&C Costs



8-20 Well (On-line 1Q 15)
- IP30 900 boepd (310 BPM, 65% Liq)

2016 Future Drilling/Completions

12-19 Pad (On-line 2Q 16)
- 03-17 IP30: 573 boepd (338 BPM, 67% Liq)
- 06-17 IP30: 752 boepd (240 BPM, 59% Liq)
- 11-17 P30: 733 boepd (338 BPM, 67% Liq)
- 09-26 IP30: 1070 boepd (272 BPM, 62% Liq)

BPM (Barrels per mmcf)

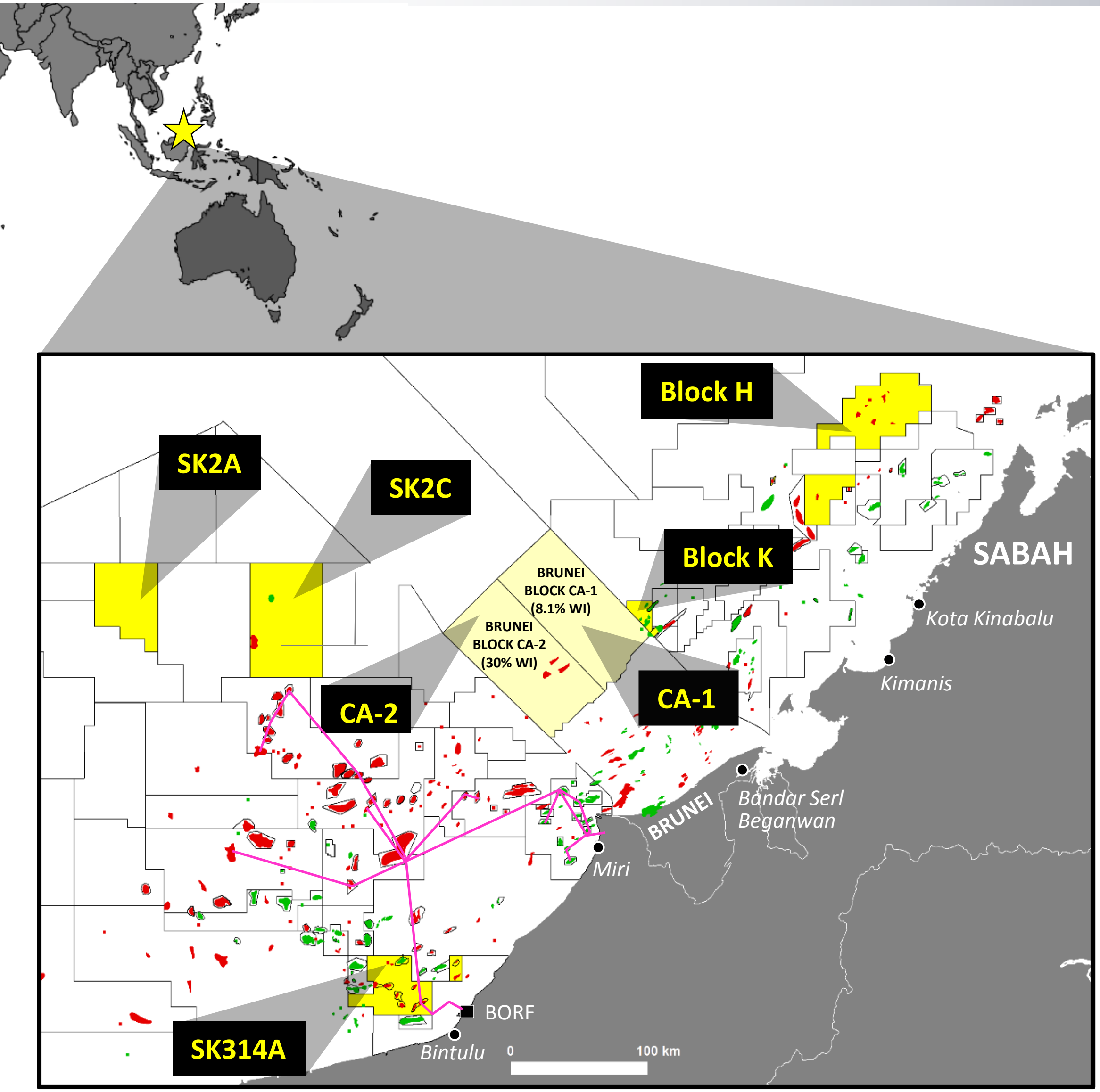
Unconventional Single Well Economics

Area	Type Curve ROR
EFS	
Catarina KBS	42%
Catarina Kone	29%
Karnes Lower	34%
Kaybob Duvernay	
Duvernay Condensate	24%
Duvernay Light Oil	36%
Montney	
Tupper Main	32%
Tupper West	44%
Placid Montney	30%

Note: Tupper Montney includes Enbridge Opex fee

May 25 Strip	***2016***	***2017***	***2018***	***2019***	***2020***
WTI ($/bbl)	$45.40	$51.63	$52.44	$53.63	$54.78
Henry Hub ($/mcf)	$2.34	$2.98	$3.01	$3.02	$3.09

Southeast Asia Offshore Operations



Extensive Operating Experience in the Area Developed Through 15+ Year Presence in the Region

Long Life, Shallow Decline Assets Provide Steady Cash Flow

Brent Linked Assets Serving Asian Markets Provides Diversity to North American Operations

Strong Relationship with Local NOC's

- Block H FLNG Project with Petronas Targeting First Production in 2020
- Brunei Natural Gas Discovery Adds Additional Resources Through a Multi-Field Development Plan
- Vietnam Cuu Long Field Provides New Entry Into Highly Successful Oil Prone Basin

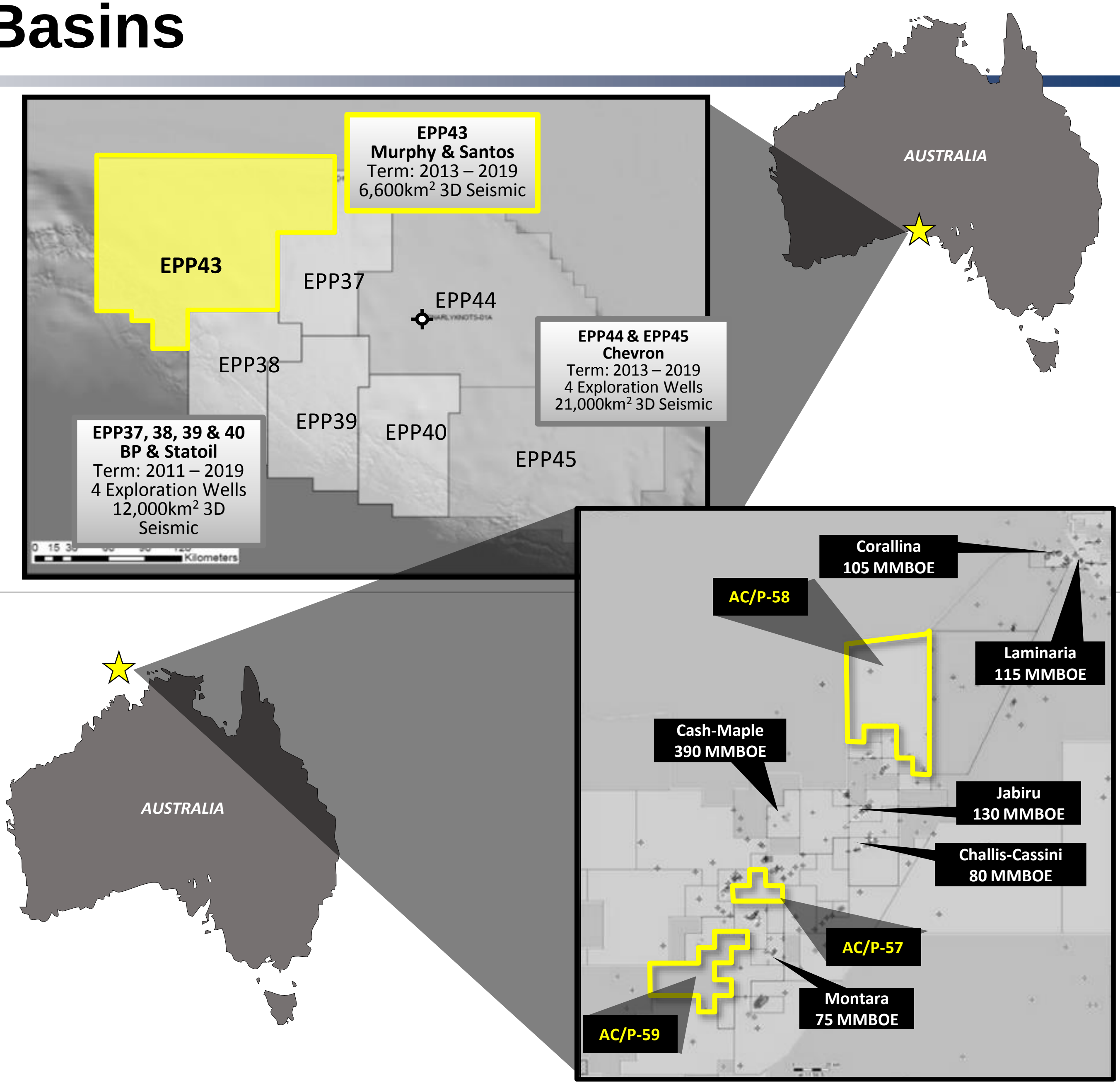
Australia – Ceduna & Vulcan Basins

Ceduna Basin

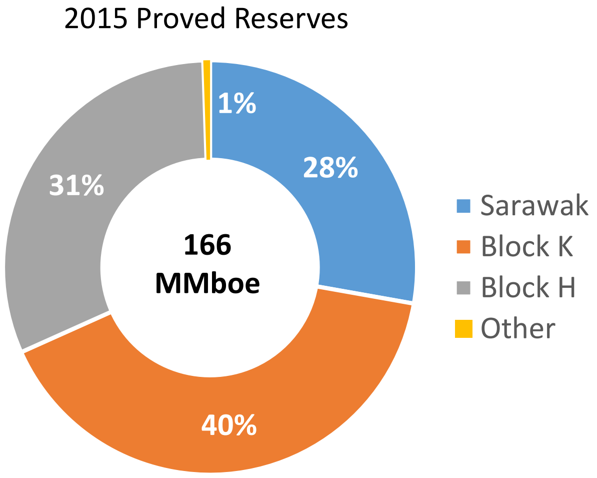
- Murphy 50% WI, Operator
- Entered with Seismic Only Commitments
- Numerous Structures Have Been Identified Through Seismic Data
- Monitor Wells to be Drilled in Adjacent Blocks
- Significant Exploration Resource Potential

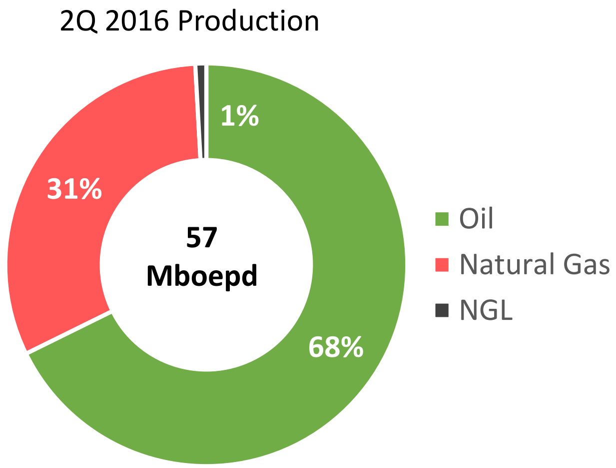
Vulcan Basin

- Murphy 60% WI, Operator
- Large Acreage Position
- Entered with Seismic Only Commitments
- Unique "Murphy Ground Floor" Entry
- Developing Forward Drilling Plans



Malaysia Overview





Kikeh

- First Production: 2007
- Subsea Tieback to FPSO or Spar
- Current Net Production: ~13,200 boepd

Siakap North Petai

- First Production: 2014
- 15 Km Subsea Tieback to Kikeh FPSO
- Current Net Production: ~3,400 boepd

Kakap - Gumusut (Non-Operated)

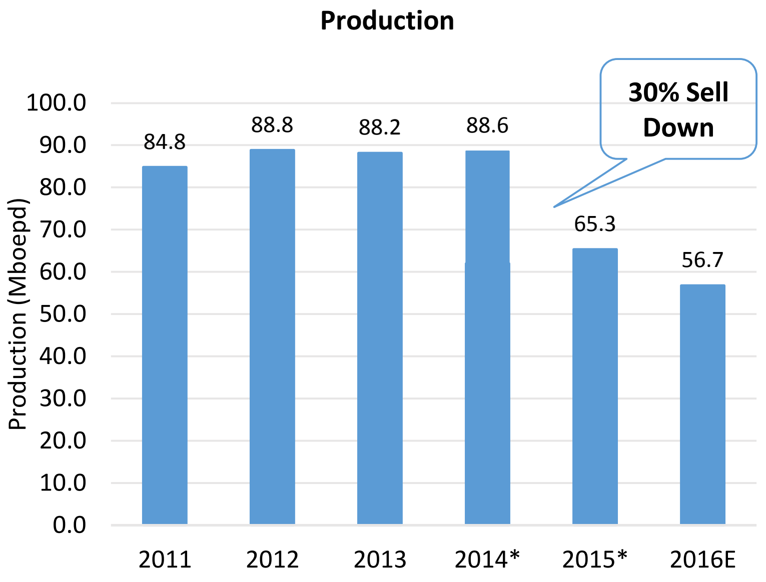
- First Production: 2012
- Current Net Production: ~9,600 boepd

Sarawak

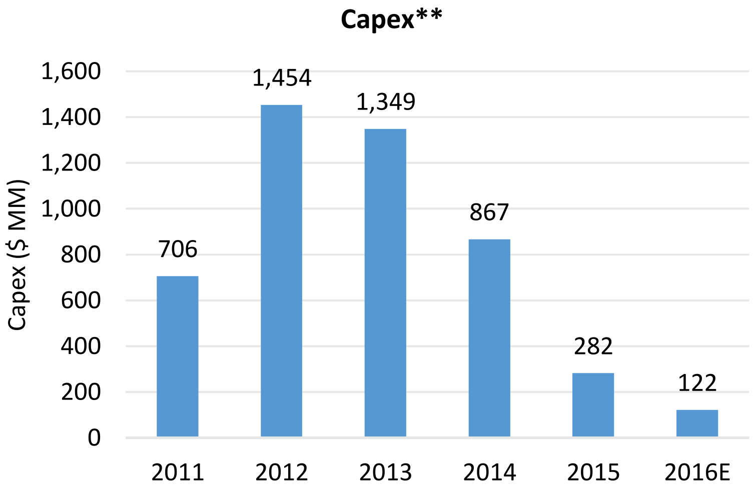
- First Oil: 2003; First Gas: 2009
- Integrated Infrastructure Provides Economies of Scale for New Field Tie-Ins
- South Acis Field Gross EUR Has More than Doubled Since 2012 to 51 MMstb
- Current Production: ~30,500 boepd

Block H

- Phase I Sanctioned in 2014
- Multiple Gas Discoveries with Low Risk Bolt On Exploration Upside

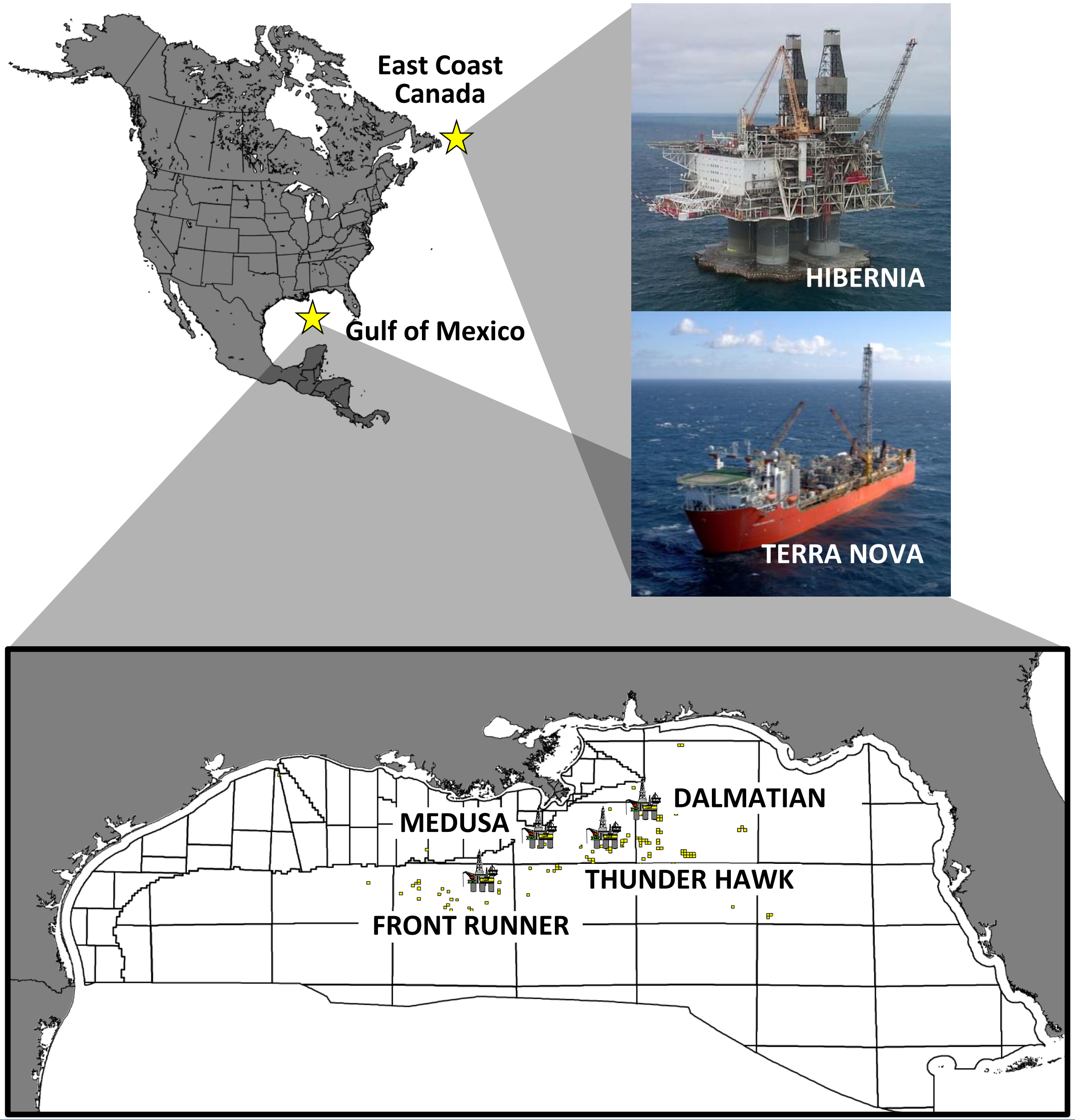


Company sold 30% of Malaysian interest in 4Q 2014 & 1Q 2015



***Net to Murphy*

North America Offshore Operations



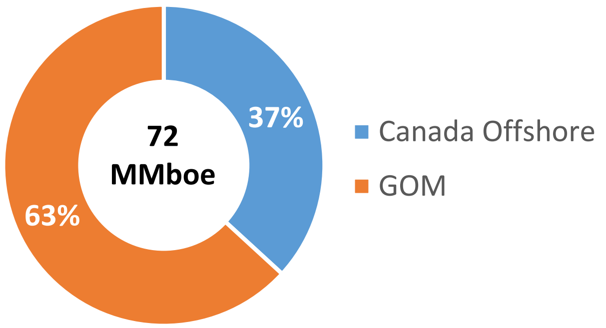
East Coast Canada

- 2 Non-Op Producing Fields
  - Hibernia
  - Terra Nova

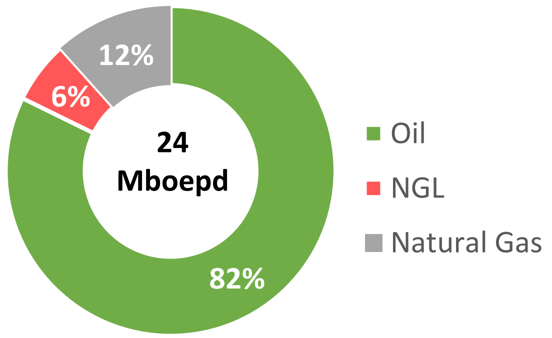
Gulf of Mexico

- 4 Operated Producing Fields
  - Medusa
  - Front Runner
  - Thunder Hawk
  - Dalmatian
- 3 Non-Op Producing Fields
  - Habanero
  - Tahoe
  - Kodiak

2015 Proved Reserves



2Q 2016 Production



Gulf of Mexico Overview

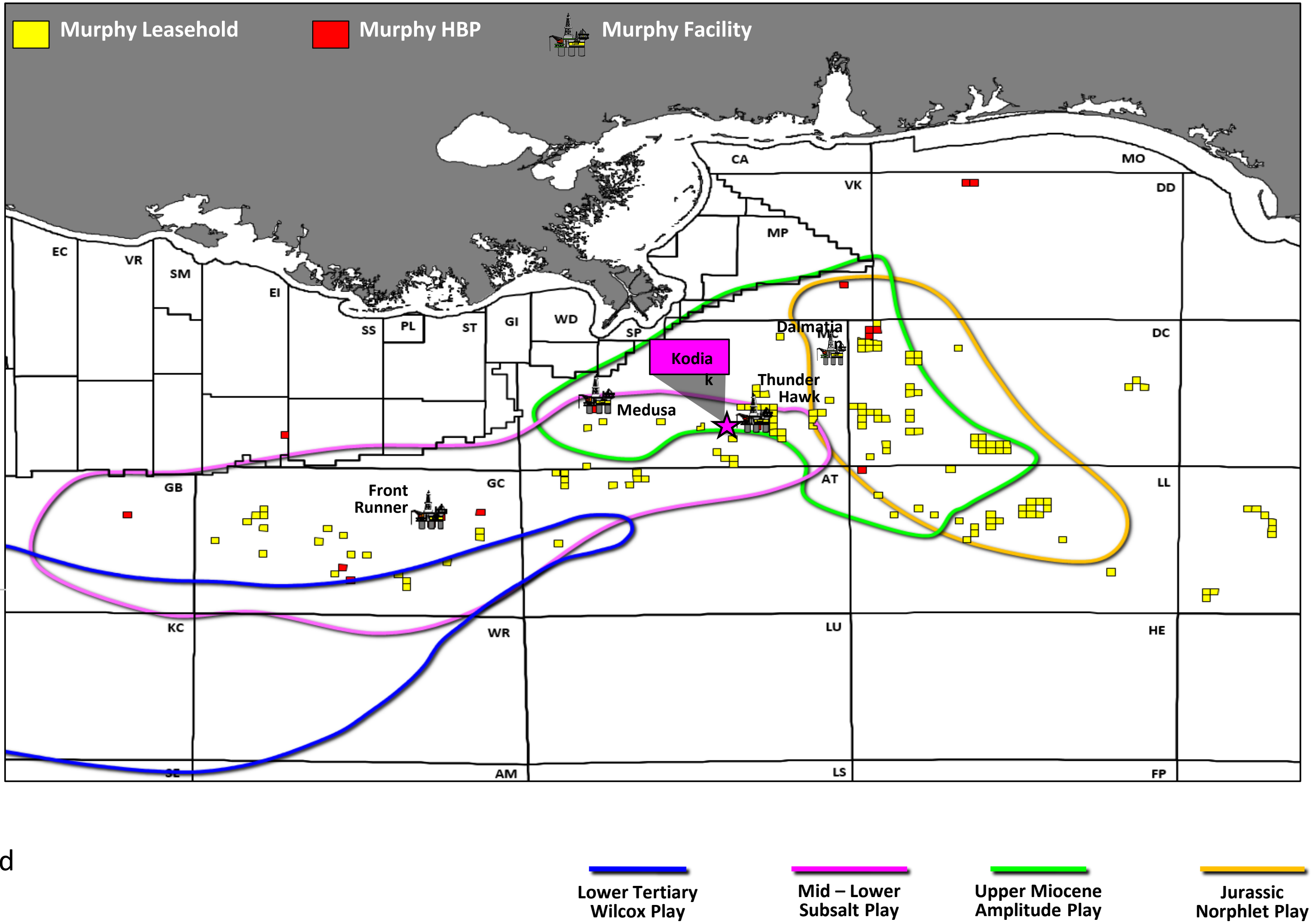
Operated

Medusa – 60% WI
- First Production: November 2003
- Current Net Production: ~4,800 boepd
- Field Expansion: 2015

Front Runner – 62.5% WI
- First Production: December 2004
- Current Net Production: ~2,100 boepd

Thunder Hawk – 62.5% WI
- First Production: July 2009
- Current Net Production: ~2,000 boepd

Dalmatian – 70% WI
- First Production: April 2014
- Current Net Production: ~3,700 boepd
- South Extension Expansion: 2015



Non-Op

Non-Op GOM
- Current Net Production: ~4,200 boepd
- Average Working Interest: ~30%
- Kodiak – 29% WI
  - On-Line 2016 Tieback to Devil's Tower
  - Current Gross Production: 12,500 boepd
  - Advancing Commingling Opportunity
  - Economic at Low Prices

Murphy's Future is Abundant with Resources

Eagle Ford Shale

- +800 MMboe Net Remaining Resource
- ~2,000 Remaining Locations
- Additional Upside from Down-spacing and Austin Chalk

Tupper Montney

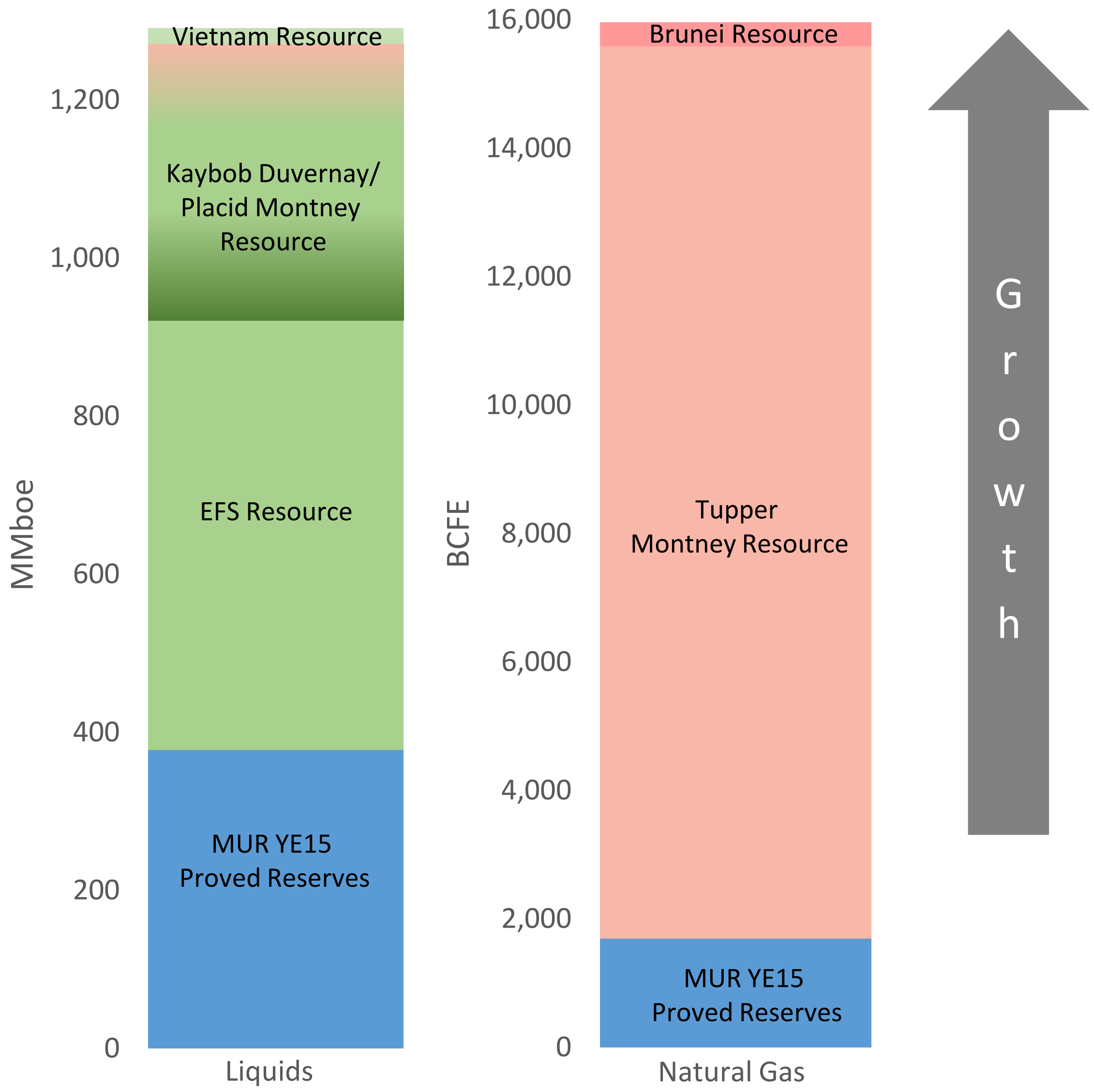
- ~14 TCF Net Remaining Resource, 28 TCF OGIP
- Additional Upside from Down-spacing

Kaybob Duvernay/Placid Montney

- 200 – 350 MMboe Net Remaining Resource
- Early Days Compared to Other Shale Plays
- Significant Upside from Down-spacing, Improved Completion Techniques
- Additional Resource from Black Oil

Southeast Asia

- Brunei Discovery Adds to Multi-Field Future Development
- Vietnam Block 15/1-05 Discovery
- Multiple Exploration Blocks Available Once Prices Recover



Note: Montney and EFS proved reserves are incorporated in MUR YE15 Proved Reserves
Excludes Syncrude reserves of 115 MMboe

Takeaways

Repositioned Company

Recalibrated Dividend – Maintain Shareholder Focus

New Capital Structure – Unsecured Credit Facility

Three Significant NA Unconventional Assets

Cash Flow Providing Offshore Business

APPENDIX

Appendix

- Non-GAAP Reconciliation
- Abbreviations
- Guidance
- Hedging Positions
- Asset Overview

Non-GAAP Financial Measure Definitions & Reconciliations

The following list of Non-GAAP financial measure definitions and related reconciliations is intended to satisfy the requirements of Regulation G of the Securities Exchange Act of 1934, as amended. This information is historical in nature. Murphy undertakes no obligation to publicly update or revise any Non-GAAP financial measure definitions and related reconciliations.

Non-GAAP Reconciliation

ADJUSTED EARNINGS

Murphy defines Adjusted Earnings as net income adjusted to exclude discontinued operations and certain other items that affect comparability between periods.

Adjusted Earnings is used by management to evaluate the Company's operational performance and trends between periods and relative to its industry competitors.

Adjusted Earnings, as reported by Murphy, may not be comparable to similarly titled measures used by other companies and it should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). Adjusted Earnings has certain limitations regarding financial assessments because it excludes certain items that affect net income. Adjusted Earnings should not be considered in isolation or as a substitute for an analysis of Murphy's GAAP results as reported.

$ Millions	**Six Months Ended – June 30, 2016**	**Six Months Ended – June 30, 2015**
Net Income (loss)	(195.9)	(88.3)
Discontinued operations (income) loss	(0.7)	2.8
Mark-to-market loss (gain) on crude oil derivate contracts	51.9	(4.8)
Foreign exchange gains	(21.3)	(35.1)
Syncrude operations, including tax benefits of $68.0 on sale	(47.9)	-
Income tax benefits associated with Montney midstream divestiture	(20.9)	-
Income tax benefits on investments in foreign areas	(9.4)	-
Oil Insurance Limited dividends	(2.2)	(4.5)
Impairment of assets	68.9	-
Restructuring charges	6.2	7.5
Gain on sale of 10% interest in Malaysia	-	(218.8)
Environmental provisions	-	35.8
Increase in Alberta corporate tax	-	23.8
Adjusted Earnings (loss)	**(171.3)**	**(281.6)**

Non-GAAP Reconciliation

EBITDA

Murphy defines EBITDA as income from continuing operations before income taxes, depreciation, depletion and amortization (DD&A), net interest expense, and impairment expense.

Management believes that EBITDA provides useful information for assessing Murphy's financial condition and results of operations and it is a widely accepted financial indicator of the ability of a company to incur and service debt, fund capital expenditure programs, and pay dividends and make other distributions to stockholders. EBITDA per barrel is computed by taking EBITDA divided by total barrels of oil equivalents produced during the respective periods.

EBITDA, as reported by Murphy, may not be comparable to similarly titled measures used by other companies and it should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). EBITDA has certain limitations regarding financial assessments because it excludes certain items that affect net income and net cash provided by operating activities. EBITDA should not be considered in isolation or as a substitute for an analysis of Murphy's GAAP results as reported.

$ Millions	**Six Months Ended – June 30, 2016**	**Six Months Ended – June 30, 2015**
Income (loss) from continuing operations	(196.6)	(85.5)
Income tax benefit	(199.7)	(142.3)
Interest expense, net of interest capitalized	64.7	56.7
DD&A expense	541.4	884.4
Impairment of assets	95.1	-
Consolidated EBITDA (Non-GAAP)	**304.9**	**713.3***

**Includes $135.8 MM pre-tax gain on sale of 10% interest in Malaysia in 2015.*

Non-GAAP Reconciliation

EBITDAX

Murphy defines EBITDAX as income from continuing operations before income taxes, exploration expenses, depreciation, depletion and amortization (DD&A), net interest expense, and impairment expense.

Management believes that EBITDAX provides useful information for assessing Murphy's financial condition and results of operations and it is a widely accepted financial indicator of the ability of a company to incur and service debt, fund capital expenditure programs, and pay dividends and make other distributions to stockholders. EBITDAX per barrel is computed by taking EBITDAX divided by total barrels of oil equivalents produced during the respective periods.

EBITDAX, as reported by Murphy, may not be comparable to similarly titled measures used by other companies and it should be considered in conjunction with net income, cash flow from operations and other performance measures prepared in accordance with generally accepted accounting principles (GAAP). EBITDAX has certain limitations regarding financial assessments because it excludes certain items that affect net income and net cash provided by operating activities. EBITDAX should not be considered in isolation or as a substitute for an analysis of Murphy's GAAP results as reported.

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Income tax benefit	(199.7)	(142.3)
Interest expense, net of interest capitalized	64.7	56.7
DD&A expense	541.4	884.4
Impairment of assets	95.1	-
Exploration expense	64.0	193.7
Consolidated EBITDAX (Non-GAAP)	**368.9**	**907.0***

**Includes $135.8 MM pre-tax gain on sale of 10% interest in Malaysia in 2015.*

Abbreviations

BBL: barrels (equal to 42 US gallons)

BCFE: billion cubic feet equivalent

BN: billions

BOE: barrels of oil equivalent (1 barrel of oil or 6000 cubic feet of natural gas)

BOEPD: barrels of oil equivalent per day

BOPD: barrels of oil per day

BPM: barrels per MMCF

CAGR: compound annual growth rate

D&C: drilling & completion

DD&A: depreciation, depletion & amortization

EBITDA: income from continuing operations before taxes, depreciation, depletion and amortization, and net interest expense

EBITDAX: income from continuing operations before taxes, depreciation, depletion and amortization, net interest expense, and exploration expenses

EFS: Eagle Ford Shale

EUR: estimated ultimate recovery

F&D: finding & development

FLNG: floating liquefied natural gas

FPSO: floating production storage and offloading

G&A: general and administrative expenses

GOM: Gulf of Mexico

HH: Henry Hub

IP: initial production

IPO: initial public offering

JV: joint venture

LC: letter of credit

LOE: lease operating expense

MBBL: thousand barrels

MBOE: thousands barrels of oil equivalent

MBOEPD: thousands of barrels of oil equivalent per day

MCF: thousands of cubic feet

MCFD: thousands cubic feet per day

MM: millions

MMBOE: millions of barrels of oil equivalent

MMBTU: million British Thermal Units

MMCF: millions of cubic feet

MMCFD: millions of cubic feet per day

MMCFEPD: million cubic feet equivalent per day

MMSTB: million stock barrels

NA: North America

NGL: natural gas liquid

NOC: national oil company

OGIP: original gas in place

PDP: proven developed

PUD: proven undeveloped

ROR: rate of return

R/P: ratio of reserves to annual production

TCF: trillion cubic feet

TCPL: TransCanada Pipeline

WI: working interest

WTI: West Texas Intermediate (a grade of crude oil)

Guidance – 3Q 2016

Guidance 3Q 2016	3Q 2016 Liquids (bopd)	3Q 2016 Gas (mcfd)
3Q Production:	103,500	390,000
US - Eagle Ford Shale	41,000	35,000
Gulf of Mexico	12,000	14,000
Canada – Heavy	3,000	2,000
Montney and Duvernay	2,000	205,000
Offshore	8,500	-
Malaysia – Sarawak	13,500	123,000
Block K	23,500	11,000
3Q Production Volume (boepd)	167,500 – 169,500	
3Q Sales Volume (boepd)	164,500 – 166,500	
3Q Exploration Expense ($MM)	$19	
Full Year 2016 Production (boepd)	173,000 – 177,000	
Full Year 2016 Capex ($MM)	$620*	
3Q Expected Realized Prices ($/bbl)	Malaysia – Block K	45.62
	Sarawak Oil	46.02
($/mcf)	Sarawak Gas	3.29

*Excludes Kaybob Duvernay / Placid Montney acquisition capex

2016 Hedging Positions

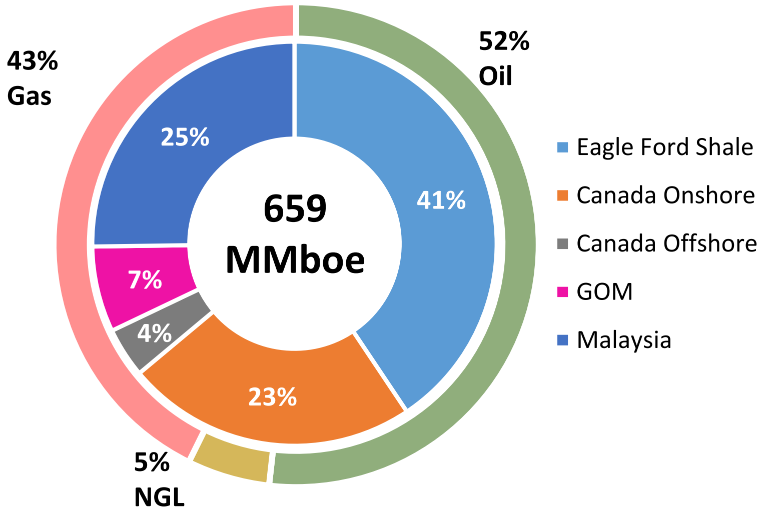
Field	Commodity	Type	Volumes (bbl/d)	Price (USD/bbl)	Start Date	End Date
United States	WTI	Fixed Price Derivative Swap	25,000	$50.67	7/1/2016	12/31/2016
United Stated	WTI	Fixed Price Derivative Swap	12,000	$50.12	1/1/2017	12/31/2017

Field	Commodity	Type	Volumes (MMcf/d)	Price (CAD/mcf)	Start Date	End Date
Montney	Natural Gas	Fixed Price Forward Sales	99	C$3.00	7/1/2016	12/31/2016
Montney	Natural Gas	Fixed Price Forward Sales	59	C$2.81	1/1/2017	12/31/2020

Asset Overview

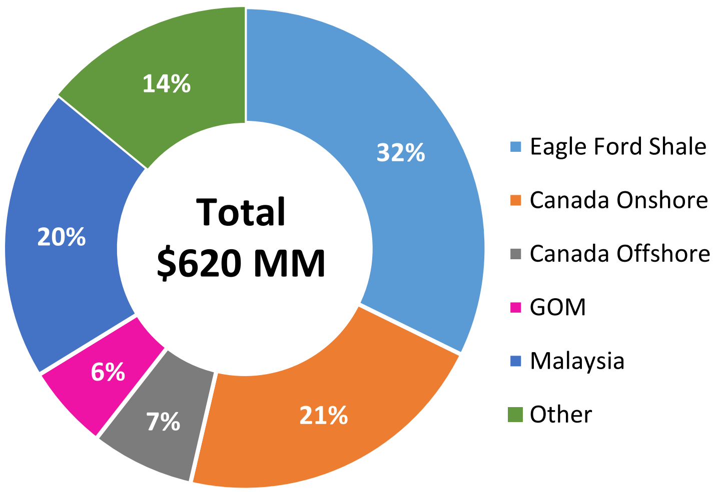
At December 31, 2015 (Excluding Syncrude)	Crude Oil	NGLs	Natural Gas	Total
Proved Developed Reserves:	(Millions of Barrels)		(Billions of Cubic Feet)	(Millions of Barrels Equivalent)
United States	125.9	20.7	148.3	171.3
Canada	23.8	0.3	453.5	99.7
Malaysia	62.1	0.6	181.7	93.0
Total Proved Developed Reserves	211.8	21.6	783.5	364.0
Proved Undeveloped Reserves:				
United States	113.0	14.7	84.1	141.7
Canada	4.1	0.1	456.1	80.2
Malaysia	12.5	-	365.1	73.4
Total Proved Undeveloped Reserves	129.6	14.8	905.3	295.3
Total Proved Reserves	341.4	36.4	1,688.8	659.3

2015 Proved Reserves*



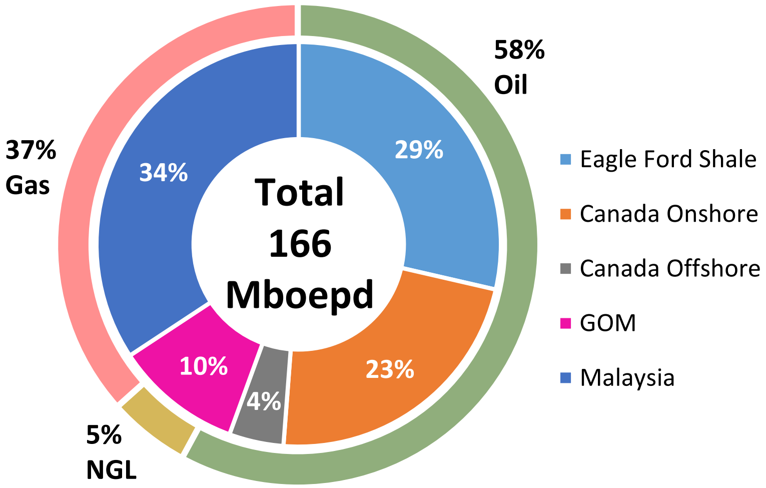
*Excludes Syncrude reserves of 115 MMboe
Kaybob Duvernay/Placid Montney closed 2Q 16

2016E CAPEX*



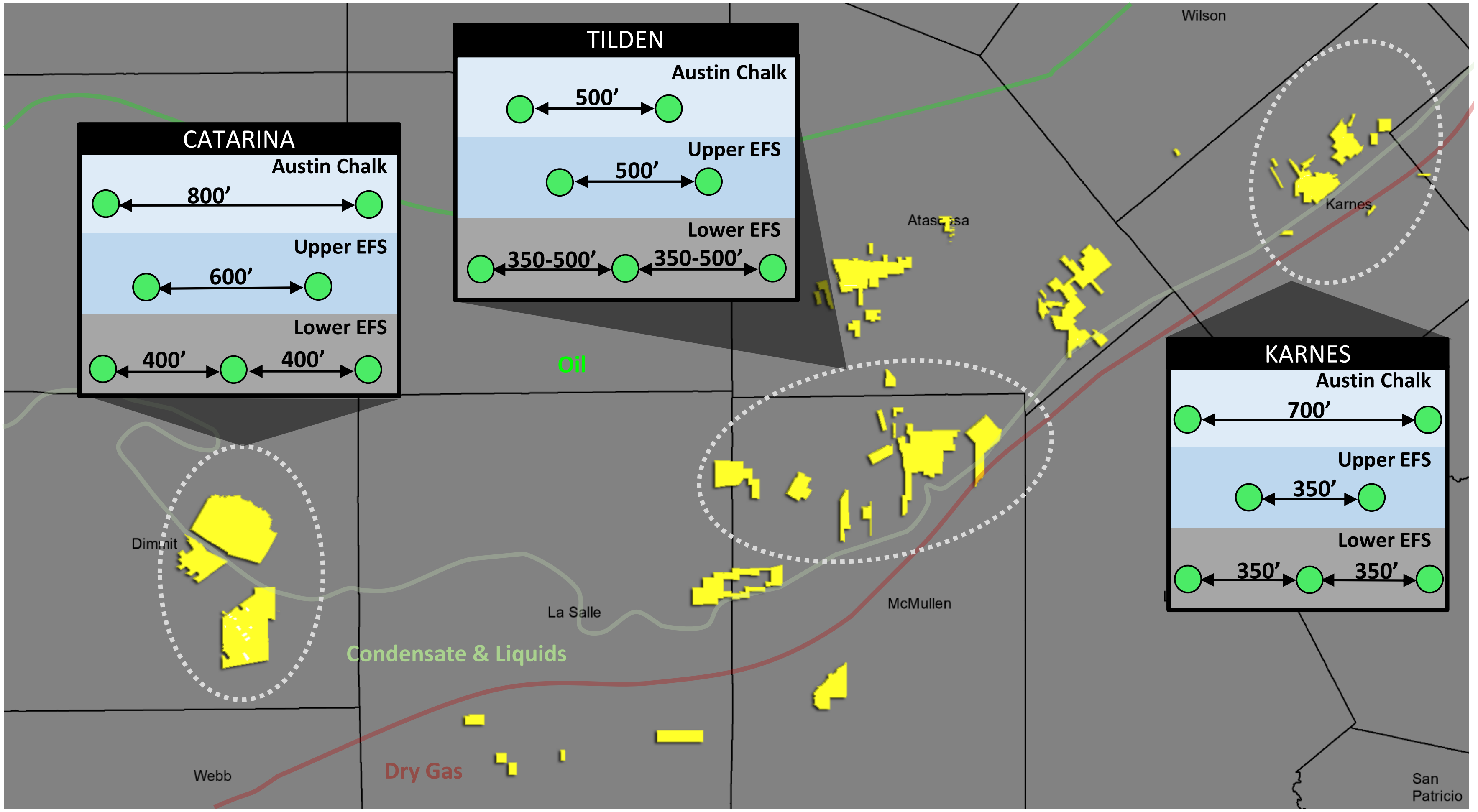
*Excludes Cost to Acquire Kaybob Duvernay and Montney Interests in Canada

2Q 16 Production*



*Excludes Syncrude production of 3.0 Mboepd

Eagle Ford Shale – Stacked Pay Potential Upside



Stacked Potential in Majority of Acreage

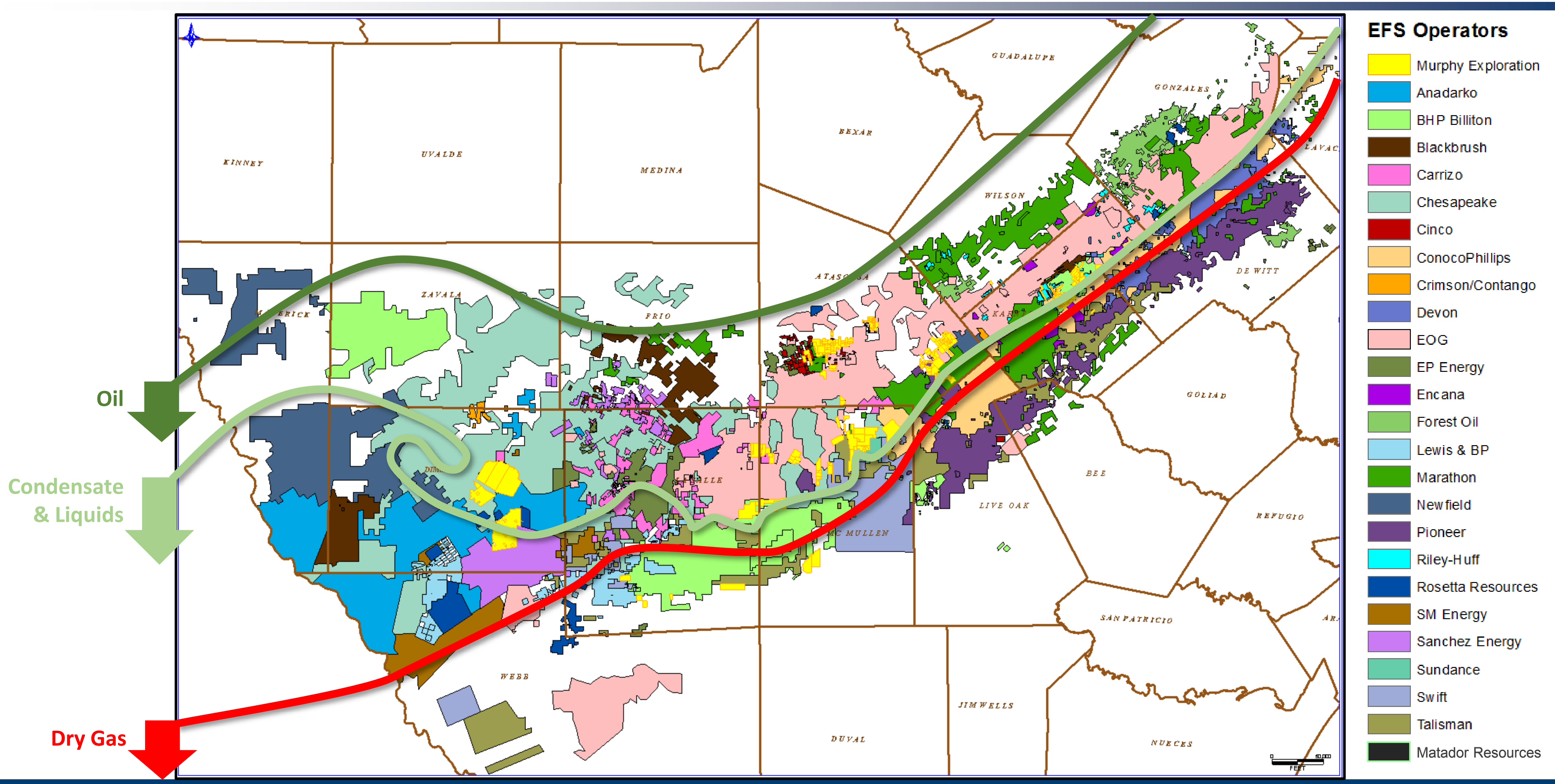
Down-spacing Testing Ongoing in Upper and Lower EFS

- ~630 locations in Upper EFS
- ~1,080 locations in Lower EFS
- Additional Upside Based on Results

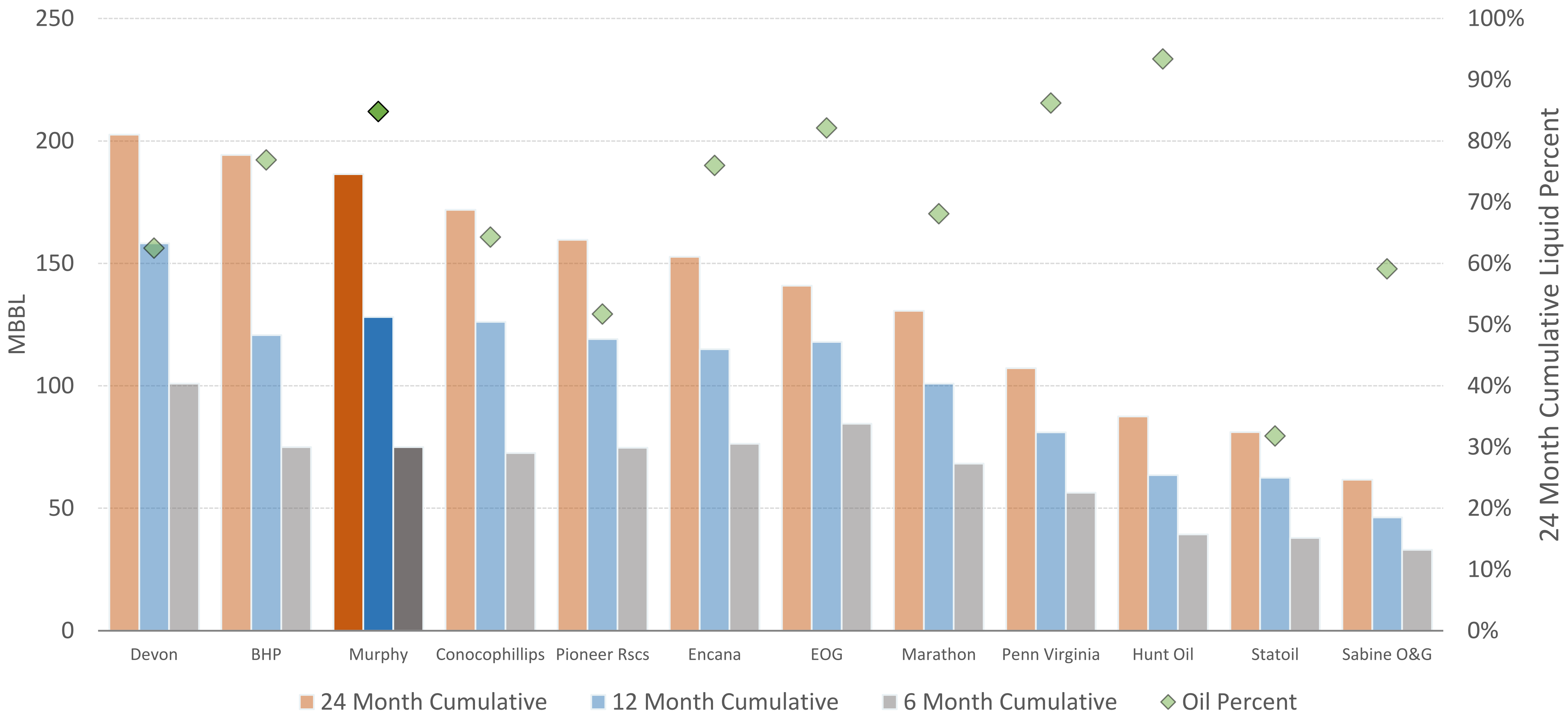
Austin Chalk

- JOG Unit A 1H Maintaining High Rate
- Completing New Wells in Karnes and Catarina Area 3Q 16
- ~365 Locations in Karnes, Tilden and Catarina
- ~80 MMboe Preliminary Net Resource
- Additional Upside Based on Results

Eagle Ford – Peer Acreage



East Eagle Ford Shale Cumulative Liquids

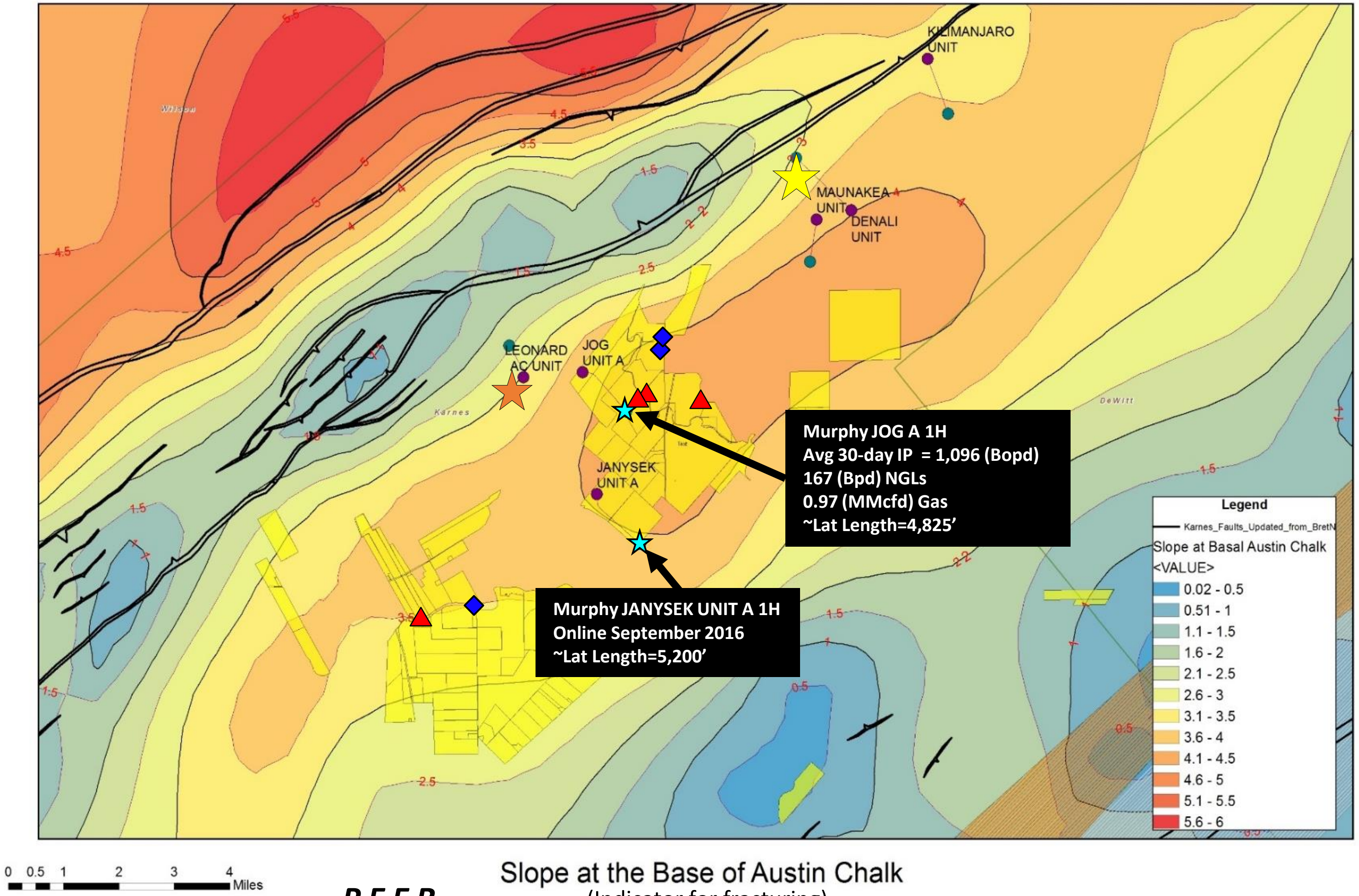


Operators >50 wells; IHS data through Jan 2016; Karnes, Wilson, DeWitt, Gonzales, Fayette, Lavaca, Live Oak counties

Austin Chalk Well Comparison

- No Major Differences in Geology/Fracturing in Peer Acreage vs MUR
- Primary Differences Are in Completions & Production

Completions Design/Production Comparison	Leading Austin Chalk Producer	Murphy Jog Unit A 1H
Cluster spacing	14’	25’
Stages	126’	200’
H20/ft	67 bbls/ft	50 bbls/ft
Sand/ft	3,100 lbs/ft	2,300 lbs/ft
100 Mesh	100%	49%
Choke	32/64	18/64



Slope at the Base of Austin Chalk
(Indicator for fracturing)

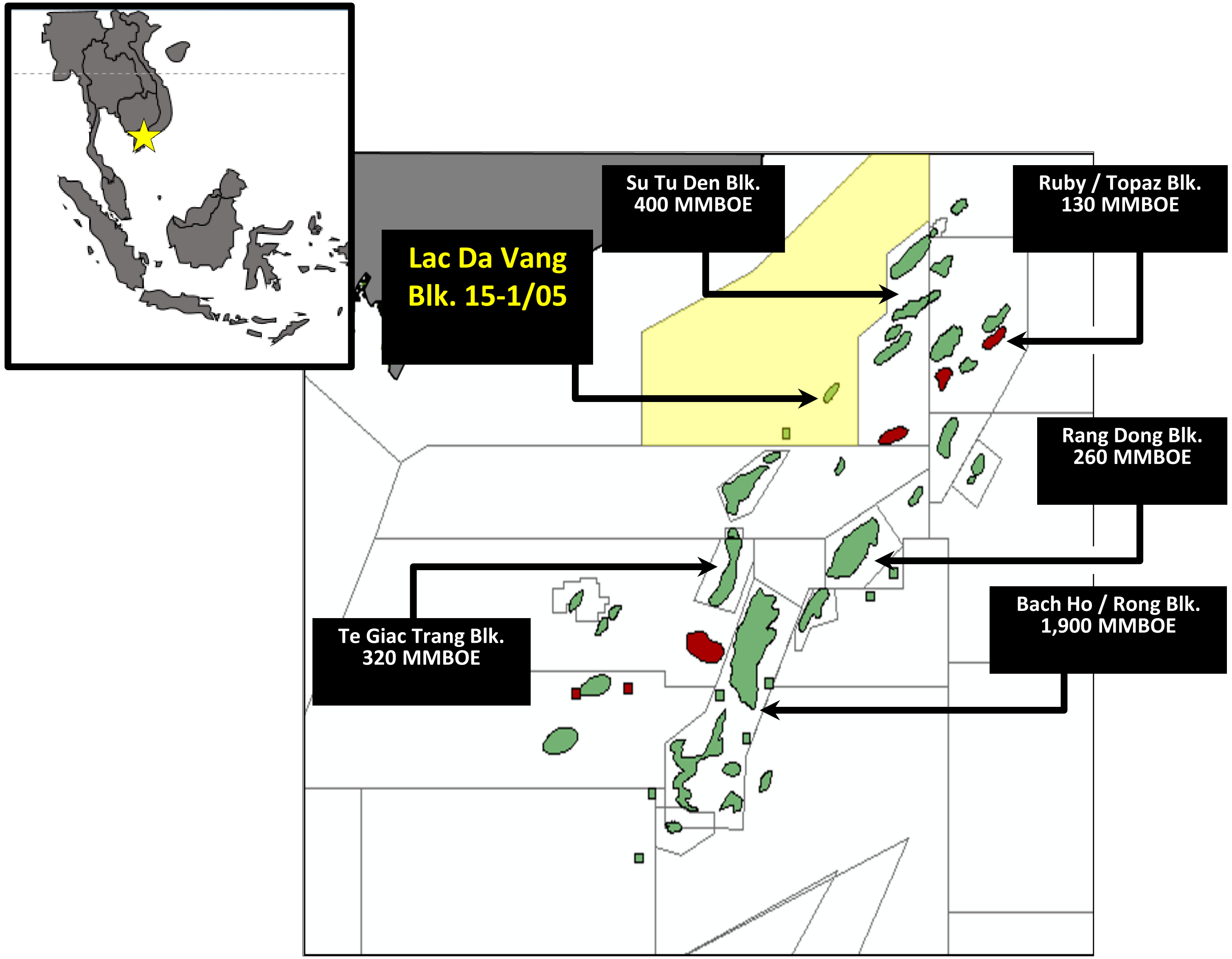
PEER

Avg 30-day IP = 2,100 bopd
298 bpd NGL
1.9 MMcfd Gas
Lateral Length ~2,800’

Avg 30-day IP = 2,265 bopd
415 bpd NGL
2.7 MMcfd Gas
Lateral Length ~6,500’

- Q4 2016 AC well
- 2017 AC well
- Existing AC well

Vietnam – Cuu Long Entry



- Signed Farm-in Agreement for Block 15-1/05
  - Material Discovered Resource with Exploration Running Room
- Highly Successful Oil Prone Basin
- Successful Appraisal & Flow Tests
- New Focus Area
  - Negotiating Additional Block Entries with PetroVietnam