FIRST QUARTER 2018 EARNINGS CONFERENCE CALL & WEBCAST
MAY 3, 2018

ROGER W. JENKINS
PRESIDENT & CHIEF EXECUTIVE OFFICER
Cautionary Statement

Cautionary Note to U.S. Investors – The United States Securities and Exchange Commission (SEC) requires oil and natural gas companies, in their filings with the SEC, to disclose proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. 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 prohibit us from including in filings with the SEC. The SEC permits the optional disclosure of probable and possible reserves in our filings with the SEC. Investors are urged to consider closely the disclosures and risk factors in our most recent Annual Report on Form 10-K filed with the SEC and any subsequent Quarterly Report on Form 10-Q or Current Report on Form 8-K that we file, available from the SEC’s website.

Forward-Looking Statements – This presentation contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements are generally identified through the inclusion of words such as “aim”, “anticipate”, “believe”, “drive”, “estimate”, “expect”, “expressed confidence”, “forecast”, “future”, “goal”, “guidance”, “intend”, “may”, “objective”, “outlook”, “plan”, “position”, “potential”, “project”, “seek”, “should”, “strategy”, “target”, “will” or variations of such words and other similar expressions. 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 these future events or results not to occur as implied by any forward-looking statement include, but are not limited to, increased volatility or deterioration in the level of crude oil and natural gas prices, deterioration in the success rate of our exploration programs or in our ability to maintain production rates and replace reserves, reduced customer demand for our products due to environmental, regulatory, technological or other reasons, adverse foreign exchange movements, political and regulatory instability in the markets where we do business, natural hazards impacting our operations, any other deterioration in our business, markets or prospects, any failure to obtain necessary regulatory approvals, any inability to service or refinance our outstanding debt or to access debt markets at acceptable prices, and adverse developments in the U.S. or global capital markets, credit markets or economies in general. For further discussion of factors that could cause one or more of these future events or results not to occur as implied by any forward-looking statement, see “Risk Factors” in our most recent Annual Report on Form 10-K filed with the SEC and any subsequent Quarterly Report on Form 10-Q or Current Report on Form 8-K that we file, available from the SEC’s website. Murphy undertakes no duty to publicly update or revise any forward-looking statements.
# 1Q 18 Overview

## Achieving High-Margin Production from Diversified Assets

- **1Q 18 Total Production** 168 MBOEPD, 58% Liquids
- **1Q 18 Offshore Production** 75 MBOEPD, 72% Liquids
- **1Q 18 Onshore Production** 92 MBOEPD, 47% Liquids
- Increased Kaybob Duvernay Production 92% Y-O-Y
- High-Margin Realizations, $63.58 per Barrel Oil Sold Weighted Avg Price

## Generating Strong Returns & Maintaining Healthy Liquidity

- Adjusted Net Income $40 MM
- Competitive EBITDAX/BOE ~$27
- Net Debt/Total Capital Employed 30%
- Invested $300 MM 1Q 18 in CAPEX, Front-End Loaded
- Strong Liquidity Position of $2 BN with No Borrowing on Credit Facility

## Returning Cash to Shareholders & Building Long-Term Portfolio

- Returned 16% of Operating Cash Flow to Shareholders through Dividend
- Executed on High Return, Low-Cost Offshore Projects in Gulf of Mexico & Malaysia
- Replenished Exploration Portfolio with Strategic Opportunities in Gulf of Mexico & Brazil

---

"We are Focused on Delivering High-Margin Production from Our Diversified Portfolio"
Diversified Portfolio Drives High Cash Margins

1Q 2018 Sales Basis Price

- Brent/MCO ( Malaysian Crude Oil)*
- LLS*
- WTI
- Oil-Indexed Gas
- Other

Transforming Crude Price Increase into Higher Margins

Premium Oil Margins Widening to WTI
Production & CAPEX Guidance Update

2018 Production Guidance
• 2Q 18 Guidance 166 – 169 MBOEPD
• FY 18 Guidance 167 – 170 MBOEPD, ~60% Liquids

2018 Annual CAPEX Guidance at $1.11 BN

Onshore
• Re-Allocated $21 MM of CAPEX from Tupper Montney to Eagle Ford Shale + Increased Eagle Ford Shale CAPEX $15 MM
  • Maintained Tupper Montney Production Guidance
  • Eagle Ford Shale – 7 Additional Online Wells

Offshore
• Increased Development CAPEX $14 MM
• Increased Exploration CAPEX $26 MM
  • Gulf of Mexico – Increased Samurai WI to 50%
  • Vietnam – Additional 5% WI in Block 15-1/05
1Q 18 Financial Overview

Adjustments to 1Q 18 Earnings
- Impact of 2017 “Tax Cuts & Jobs Act” $120 MM
- Foreign Exchange Gains $12 MM
- Mark-to-Market Loss on Crude Oil Contract $11 MM

Balance Sheet
- Low Leverage (2.06x Total Debt/EBITDA) with ~$2 BN Liquidity & No Near-Term Debt Maturities
- $2.8 BN Total Debt (Excluding Capital Lease)
- $940 MM Cash & Cash Equivalents
- 38% Total Debt / Total Capitalization
- 30% Net Debt / Total Capitalization

Hedge Positions April 30, 2018
- 21,000 BPD at US$54.88/BBL, Bal 2018
- 59 MMCFD at AECO C$2.81/MCF, April 1, 2018 – Dec 31, 2020

<table>
<thead>
<tr>
<th>$MM (Except per Share)</th>
<th>1Q 2018</th>
<th>1Q 2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuing Operations</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Income (Loss)</td>
<td>169</td>
<td>57</td>
</tr>
<tr>
<td>$/Diluted Share</td>
<td>0.97</td>
<td>0.33</td>
</tr>
<tr>
<td>Adjusted Earnings</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Adjusted Earnings (Loss)</td>
<td>40</td>
<td>(10)</td>
</tr>
<tr>
<td>$/Diluted Share</td>
<td>0.23</td>
<td>(0.06)</td>
</tr>
</tbody>
</table>
1Q 18 Financial Details

Operating Expenses (OPEX)
• 1Q 18 $9.07/BOE
  • $0.70/BOE Higher Due to Workover Expenses at Kodiak
  • $0.42/BOE Higher Due to Offset Frac Impacts at Eagle Ford Shale
    • Impacted by Additional Sand & Water Disposal Costs as a Result of Offset Fracs
  • 2Q – 3Q 18 Scheduled Maintenance Offshore Canada & Malaysia

Tax Items in 1Q 18
• Current Tax Provision, Primarily in Malaysia & Canada, Partially Offset Deferred Tax Credit of $120 MM
• One-Time Withholding Tax Payment of $35 MM in Canada Due to Repatriation of $700 MM to US

Strong Operating Cash Flow Offset by One-Time Payment
• $278 MM Cash Flow from Operations Decreased by One-Time $35 MM Withholding Tax Payment
PORTFOLIO REVIEW
Eagle Ford Shale 1Q 18 Highlights

**Operated Well Delivery**
- 45 Wells Online FY 18, Increase from Prior Guidance of 38 Wells
- 6 Tilden Wells Online 1Q 18 – Avg IP30 775 BOEPD
- 22 Wells Online 2Q 18 – 10 Well Pad in Karnes, 10 Wells in Catarina & 2 Wells in Tilden
- 4 Wells Online 3Q 18 in Tilden
- 13 Wells Online 4Q 18 in Catarina

**Improved Drilling Performance**
- 1Q 18 Drilling Cost per Foot $110
- 1Q 18 Completion $/CLAT $700
Tupper Montney 1Q 18 Highlights

Top Tier North American Dry Natural Gas Play

Recent Activity
• Drilled Remaining 3 of 5 Wells at 14-01 Pad, 3 Upper Montney, 2 Middle Montney – Avg EUR ~18 BCF
• Drilled 4 Consecutive Pacesetter Wells – $83 Drilling Cost per Foot, $384/CLAT

1Q 18 Netback C$2.20/MCF* vs AECO C$2.08/MCF
• Full Cycle Break-Even ~C$1.90/MCF AECO

Expansion Project – Progressing FEED for 2018 Sanction
• Break-Even ~C$1.75/MCF AECO

*Including Transportation Costs of C$0.27/MCF

Mitigating AECO Exposure – 2018 Montney Natural Gas Sales

*Source: Tudor, Pickering, Holt & Co.

2017 Realized & 2018 – 2020 Forward Sales Price, C$/MCF
Kaybob Duvernay 1Q 18 Highlights

Increased Kaybob Production 92% from 1Q 17 to 1Q 18

Drilling Pacesetter Wells
• 1Q 18 Drilling Cost per Foot $110
• 1Q 18 $/CLAT $600

Appraisal Wells Update – Online 1Q 18
• 01-12 Pad (1 Well) – Oil, IP30 900 BOEPD, 80% Liquids
• 15-16 Pad (2 Wells) – Oil, Average IP30 985 BOEPD, 70% Liquids
• 12-29 Pad (2 Wells) – Oil, Average IP30 1,040 BOEPD, 80% Liquids
• 16-03 Pad (3 Wells) – Condensate, IP Potential 2,000 BOEPD per Well Average, 50% Liquids
2018 Appraisal & Development Plan
- Maintained Budget & Contingent Well Counts
- Budget: Drill 17 Wells, Online 23 Wells
- Contingent: Drill +7 Wells, Online +7 Wells

<table>
<thead>
<tr>
<th>Pad</th>
<th>Wells</th>
<th>Window</th>
<th>Online</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>01-12</td>
<td>1</td>
<td>Oil 1Q 2018</td>
</tr>
<tr>
<td>✓</td>
<td>B</td>
<td>15-16</td>
<td>2 Oil 1Q 2018</td>
</tr>
<tr>
<td>✓</td>
<td>C</td>
<td>12-29</td>
<td>2 Oil 1Q 2018</td>
</tr>
<tr>
<td>✓</td>
<td>D</td>
<td>16-03</td>
<td>3 Condensate 1Q 2018</td>
</tr>
<tr>
<td>E</td>
<td>03-33</td>
<td>4</td>
<td>Oil 2Q 2018</td>
</tr>
<tr>
<td>F</td>
<td>16-06</td>
<td>2</td>
<td>Oil 3Q 2018</td>
</tr>
<tr>
<td>G</td>
<td>11-14</td>
<td>5</td>
<td>Condensate 3Q 2018</td>
</tr>
<tr>
<td>H</td>
<td>16-18</td>
<td>3</td>
<td>Oil 3Q 2018</td>
</tr>
<tr>
<td>I</td>
<td>04-21</td>
<td>1</td>
<td>Oil 3Q 2018</td>
</tr>
<tr>
<td>J*</td>
<td>16-14</td>
<td>4</td>
<td>Oil 4Q 2018</td>
</tr>
<tr>
<td>K*</td>
<td>08-03</td>
<td>3</td>
<td>Oil 4Q2018</td>
</tr>
</tbody>
</table>

* Contingent: Additional Capital Required Beyond 2018 Budget
Offshore Operations 1Q 18 Highlights

Malaysia
Sabah
• Kikeh – DTU Gas Lift Project 80% Complete, Online 3Q 18
• Kakap – ~155 MBOPD 1Q 19 Avg Gross Production, Phase 2 Drilling to Start 4Q 18

Block H
• FLNG Project on Track
• Targeting First Production in 2020

Vietnam
Block 15-01/05 LDV Field
• Progressing LDV Field Development Plan
• Field Will Deliver Meaningful Free Cash Flow Within 5 Years

Transfer Learnings & Expertise Between Projects
• Block 15-01/05 Very Similar to Established Malaysia SK Oil Project
• Leveraging In-House Technical Knowledge

Gulf of Mexico
Operated
• Medusa – Subsea Well Workover Complete
• Clipper – Comingled Wells Outperforming, Current Gross Rate 3,200 BOEPD

Non-Operated
• Kodiak – Resumed Production
  • Current Gross Rate 22,000 BOEPD, ~1,000+ BOEPD Above Expectations
• Habanero – Resumed Production
  • Current Gross Rate 3,700 BOEPD
1Q 18 Exploration Update

**GOM Deepwater – Samurai (GC 432)**
- Murphy 50% WI, Operator
- Spud Appraisal Well 2Q 18, Net Well Cost ~$30 MM
- Mean Gross Resource Potential 75 MMBOE, Gross Resource Upside Potential 200 MMBOE

**GOM Deepwater – New Low-Cost Blocks**
- Farmed-In to Highgarden Prospect (GC 895), Murphy 40% WI, Operator
- High Bidder on Blocks GC 939 & MC 599 at Lease Sale 250

**Brazil Bid Round 15**
- Successful Bidder on Sergipe-Alagoas Basin Blocks 430 & 573
- Murphy 20% WI, Non-Op
- Same Co-Venture Group
- $440,000 Net, No Well Commitments

**Vietnam Cuu Long Basin Block 15-1/05**
- Murphy 35% WI, Non-Op – Working to Become Operator, Increase to 40% WI
2Q – 4Q 18 Exploration Plan

GOM King Cake Prospect (AT 23)
- Murphy 31.5% WI, Operator
- Expected Spud 3Q 18
- Mean Gross Resource Potential 50 MMBOE
- Gross Resource Upside Potential 100 MMBOE
- Net Well Cost ~$22 MM
- Success Full Cycle IRR > 30%*

Mexico Palenque Prospect (Deepwater Block 5)
- Murphy 30% WI, Operator, Partners PETRONAS, Ophir & Sierra Oil & Gas
- Expected Spud 4Q 18
- Mean Gross Resource Potential ~200 MMBOE
- Gross Resource Upside Potential 500 MMBOE
- Equivalent to ~100 US GOM Blocks
- Reviewing Newly Processed Wide Azimuth Seismic, Confirms Multiple Prospects
- Block Potential 1+ BBOE Gross, 300+ MMBOE Net Recoverable Resource
- Net Well Cost ~$15 MM
- Success Full Cycle IRR > 25%*

Cuu Long Basin LDT Prospect (Block 15-1/05)
- Murphy 35% WI, Non-Op – Working to Become Operator & Increase to 40% WI
- Expected Spud 3Q 18
- Mean Gross Resource Potential 30 MMBOE
- Gross Resource Upside Potential 250 MMBOE
- Net Well Cost ~$15 MM at 40% WI
- Success Full Cycle IRR ~30%*

*Assumes WTI $52/BBL & HH $3.00/MCF, Escalated at 5%
LOOKING AHEAD
Our Strategy in Action Drives EBITDA Growth

• Measured, Oil-Weighted Production Growth Within Cash Flow while Delivering Value to Shareholders, Consistent Dividend Policy & Free Cash Flow Generation

• EBITDA 4 Year CAGR ~15%

• Plan Returns Over $800 MM to Shareholders with Current Dividend Policy

• Plan Delivers Over $500 MM Free Cash Flow, In Addition to Dividend

• Adding ~200 MMBOE Reserves by 2022

• Targeting Total Debt/EBITDA ~1.0x

• Resilience to Downside & Considerable Upside at Higher Oil Prices

*Assumes WTI $52/BBL & HH $3.00/MCF, Escalated at 5%
Takeaways

- Executing on the 2018 Plan
- Achieving High Cash Margins from Diverse, Oil-Weighted Portfolio
- Focusing on Cost Structure
- Implementing New Exploration Strategy
- Continuing to Return Cash to Shareholders with Current Dividend Policy
- Positioning Company for Long-Term Value Creation
Appendix

• Non-GAAP Reconciliation
• Abbreviations
• Guidance
• Hedging Positions
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.

<table>
<thead>
<tr>
<th>$ Millions</th>
<th>Three Months Ended – March 31, 2018</th>
<th>Three Months Ended – March 31, 2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income</td>
<td>168.3</td>
<td>58.5</td>
</tr>
<tr>
<td>Discontinued operations loss (income)</td>
<td>0.4</td>
<td>(1.0)</td>
</tr>
<tr>
<td>Impact of tax reform</td>
<td>(120.0)</td>
<td>-</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on crude oil derivate contracts</td>
<td>11.3</td>
<td>(26.0)</td>
</tr>
<tr>
<td>Foreign exchange losses (gains)</td>
<td>(11.9)</td>
<td>11.6</td>
</tr>
<tr>
<td>Seal insurance proceeds</td>
<td>(8.2)</td>
<td>-</td>
</tr>
<tr>
<td>Deferred tax on undistributed foreign earnings</td>
<td>-</td>
<td>54.6</td>
</tr>
<tr>
<td>Tax benefits on investments in foreign areas</td>
<td>-</td>
<td>(11.9)</td>
</tr>
<tr>
<td>Gain on sale of assets</td>
<td>-</td>
<td>(96.0)</td>
</tr>
<tr>
<td><strong>Adjusted Income (Loss)</strong></td>
<td><strong>39.9</strong></td>
<td><strong>(10.2)</strong></td>
</tr>
</tbody>
</table>
Non-GAAP Reconciliation

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

Management believes that EBITDA and 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.

EBITDA and 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). EBITDA and EBITDAX have certain limitations regarding financial assessments because they excludes certain items that affect net income and net cash provided by operating activities. EBITDA and EBITDAX should not be considered in isolation or as a substitute for an analysis of Murphy’s GAAP results as reported.

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended – March 31, 2018</th>
<th>Three Months Ended – March 31, 2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income</td>
<td>168.3</td>
<td>58.5</td>
</tr>
<tr>
<td>Discontinued operations loss (income)</td>
<td>0.4</td>
<td>(1.0)</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>(71.6)</td>
<td>97.4</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>45.0</td>
<td>44.6</td>
</tr>
<tr>
<td>DD&amp;A expense</td>
<td>230.7</td>
<td>236.2</td>
</tr>
<tr>
<td><strong>Consolidated EBITDA (Non-GAAP)</strong></td>
<td><strong>372.8</strong></td>
<td><strong>435.7</strong></td>
</tr>
<tr>
<td>Exploration Expense</td>
<td>28.9</td>
<td>28.7</td>
</tr>
<tr>
<td><strong>Consolidated EBITDAX (Non-GAAP)</strong></td>
<td><strong>401.7</strong></td>
<td><strong>464.4</strong></td>
</tr>
</tbody>
</table>

*EBITDA and EBITDAX for the three months ended March 31, 2018 included certain pretax items that decreased both amounts by $8 million
Non-GAAP Reconciliation

ADJUSTED EBITDAX

Murphy defines Adjusted EBITDAX as income from continuing operations before interest, taxes, depreciation and amortization (DD&A), exploration expense, impairment expense, foreign exchange gains and losses, mark-to-market loss on crude oil derivative contracts, accretion of asset retirement obligations and certain other items that management believes affect comparability between periods.

Adjusted EBITDAX is used by management to evaluate the company’s operational performance and trends between periods and relative to its industry competitors.

Adjusted EBITDAX 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 EBITDAX has certain limitations regarding financial assessments because it excludes certain items that affect net income and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Murphy’s GAAP results as reported.

<table>
<thead>
<tr>
<th>$ Millions</th>
<th>Three Months Ended – March 31, 2018</th>
<th>Three Months Ended – March 31, 2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Consolidated EBITDAX</td>
<td>401.7</td>
<td>464.4</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on crude oil derivative contracts</td>
<td>14.4</td>
<td>(39.9)</td>
</tr>
<tr>
<td>Foreign exchange (gain) loss</td>
<td>(16.6)</td>
<td>13.8</td>
</tr>
<tr>
<td>Accretion of asset retirement obligations</td>
<td>9.9</td>
<td>10.6</td>
</tr>
<tr>
<td>Other</td>
<td>0.3</td>
<td>(132.0)</td>
</tr>
<tr>
<td>Adjusted EBITDAX (Non-GAAP)</td>
<td>409.7</td>
<td>316.9</td>
</tr>
<tr>
<td>Total barrels of oil equivalents sold (boe)</td>
<td>15,043.7</td>
<td>14,757.5</td>
</tr>
<tr>
<td>Adjusted EBITDAX per boe (Non-GAAP)</td>
<td>27.23</td>
<td>21.47</td>
</tr>
</tbody>
</table>
Abbreviations

BBL: barrels (equal to 42 US gallons)
BCF: billions of cubic feet
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
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, and net interest expense, and exploration expenses
EFS: Eagle Ford Shale
EUR: estimated ultimate recovery
F&D: finding & development
FLNG: floating liquefied natural gas
G&A: general and administrative expenses
GOM: Gulf of Mexico
HCPV: hydrocarbon pore volume
JV: joint venture
LOE: lease operating expense
LLS: Light Louisiana Sweet (a grade of crude oil, includes pricing for GOM and EFS)
LNG: liquefied natural gas
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
MMCF: millions of cubic feet
MMCFD: millions of cubic feet per day
MMCFEPD: million cubic feet equivalent per day
MMSTB: million stock barrels
MCO: Malaysia Crude Official Selling Price, differential to average monthly calendar price of Platts Dated Brent for delivery month
NA: North America
NGL: natural gas liquid
ROR: rate of return
R/P: ratio of reserves to annual production
TCF: trillion cubic feet
TCPL: TransCanada Pipeline
TOC: total organic content
WI: working interest
WTI: West Texas Intermediate (a grade of crude oil)
## Guidance – 2Q 2018

<table>
<thead>
<tr>
<th>Guidance 2Q</th>
<th>2Q 2018 Liquids (BOPD)</th>
<th>2Q 2018 Gas (MCFD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2Q Production:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>US – Eagle Ford Shale</td>
<td>38,600</td>
<td>31,000</td>
</tr>
<tr>
<td>Gulf of Mexico</td>
<td>15,350</td>
<td>12,600</td>
</tr>
<tr>
<td>Canada – Tupper Montney</td>
<td>–</td>
<td>233,800</td>
</tr>
<tr>
<td>Kaybob Duvernay &amp; Placid Montney</td>
<td>5,500</td>
<td>23,500</td>
</tr>
<tr>
<td>Offshore</td>
<td>8,300</td>
<td>–</td>
</tr>
<tr>
<td>Malaysia – Sarawak</td>
<td>12,600</td>
<td>107,000</td>
</tr>
<tr>
<td>Block K/Brunei</td>
<td>18,150</td>
<td>6,100</td>
</tr>
<tr>
<td>2Q Production Volume (BOEPD)</td>
<td>166,000 – 169,000</td>
<td></td>
</tr>
<tr>
<td>2Q Sales Volume (BOEPD)</td>
<td>166,000 – 169,000</td>
<td></td>
</tr>
<tr>
<td>2Q Exploration Expense ($MM)</td>
<td>$41.0</td>
<td></td>
</tr>
<tr>
<td>Full Year 2018 Production (BOEPD)</td>
<td>167,000 – 170,000</td>
<td></td>
</tr>
<tr>
<td>Full Year 2018 Capex ($BN)</td>
<td>$1.11</td>
<td></td>
</tr>
<tr>
<td>2Q Expected Realized Prices ($/BBL)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Malaysia – Block K Oil</td>
<td>$64.50</td>
<td></td>
</tr>
<tr>
<td>Sarawak Oil</td>
<td>$64.30</td>
<td></td>
</tr>
<tr>
<td>($/MCF)</td>
<td>Sarawak Gas</td>
<td>$3.90</td>
</tr>
</tbody>
</table>
## 2018 Hedging Positions

<table>
<thead>
<tr>
<th>Area</th>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (BOPD)</th>
<th>Price (USD/BBL)</th>
<th>Start Date</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>United States</td>
<td>WTI</td>
<td>Fixed Price Derivative Swap</td>
<td>21,000</td>
<td>$54.88</td>
<td>4/1/2018</td>
<td>12/31/2018</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Area</th>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (MMCFD)</th>
<th>Price (MCF)</th>
<th>Start Date</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montney</td>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales</td>
<td>59</td>
<td>C$2.81</td>
<td>4/1/2018</td>
<td>12/31/2020</td>
</tr>
</tbody>
</table>
### Asset Overview

#### At December 31, 2017

<table>
<thead>
<tr>
<th></th>
<th>Crude Oil (Millions of Barrels)</th>
<th>NGLs (Billions of Cubic Feet)</th>
<th>Natural Gas (Millions of Barrels Equivalent)</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Reserves:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>United States</td>
<td>126.3</td>
<td>23.3</td>
<td>127.7</td>
<td>170.9</td>
</tr>
<tr>
<td>Canada</td>
<td>21.9</td>
<td>1.0</td>
<td>547.0</td>
<td>114.1</td>
</tr>
<tr>
<td>Malaysia</td>
<td>37.3</td>
<td>0.3</td>
<td>144.6</td>
<td>61.7</td>
</tr>
<tr>
<td><strong>Total Proved Developed Reserves</strong></td>
<td><strong>185.5</strong></td>
<td><strong>24.6</strong></td>
<td><strong>819.3</strong></td>
<td><strong>346.7</strong></td>
</tr>
<tr>
<td>Proved Undeveloped Reserves:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>United States</td>
<td>98.4</td>
<td>19.7</td>
<td>95.6</td>
<td>134.0</td>
</tr>
<tr>
<td>Canada</td>
<td>29.6</td>
<td>4.6</td>
<td>665.5</td>
<td>145.1</td>
</tr>
<tr>
<td>Malaysia</td>
<td>14.6</td>
<td>-</td>
<td>346.7</td>
<td>72.4</td>
</tr>
<tr>
<td><strong>Total Proved Undeveloped Reserves</strong></td>
<td><strong>142.6</strong></td>
<td><strong>24.3</strong></td>
<td><strong>1,107.8</strong></td>
<td><strong>351.5</strong></td>
</tr>
<tr>
<td><strong>Total Proved Reserves</strong></td>
<td><strong>328.1</strong></td>
<td><strong>48.9</strong></td>
<td><strong>1,927.1</strong></td>
<td><strong>698.2</strong></td>
</tr>
</tbody>
</table>

#### 2017 Proved Reserves

- **698 MMBOE**
  - 46% Gas
  - 37% Oil
  - 7% NGL
  - 19% US Onshore
  - 7% Canada Onshore
  - 3% Canada Offshore
  - 7% GOM
  - 3% Malaysia

#### 2017 CAPEX

- **$976 MM**
  - 81% Onshore
  - 19% Offshore
  - 9% US Onshore
  - 6% Canada Onshore
  - 2% Malaysia
  - 6% North America Offshore
  - 2% Exploration
  - 2% Other

#### 2017 Production

- **164 MBOEPD**
  - 55% Oil
  - 32% Gas
  - 14% US Onshore
  - 29% Canada Onshore
  - 25% Malaysia
  - 25% North America Offshore
  - 6% NGL

---

*Note: The percentages and values are illustrative and may not reflect actual figures.*
## NA Onshore Running Room

<table>
<thead>
<tr>
<th>Area</th>
<th>Net Acres</th>
<th>PDP Wells</th>
<th>Reservoir</th>
<th>Remaining Wells</th>
<th>Spacing (Acres)</th>
<th>Inter-Well Spacing (ft)</th>
<th>Total Well Count*</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>NA Onshore</strong></td>
<td><strong>Total</strong></td>
<td><strong>413,156</strong></td>
<td><strong>1,222</strong></td>
<td><strong>5,176</strong></td>
<td></td>
<td></td>
<td><strong>6,398</strong></td>
</tr>
<tr>
<td>Karnes</td>
<td>10,918</td>
<td>274</td>
<td>Lower EFS</td>
<td>60</td>
<td>40</td>
<td>350</td>
<td>599</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>158</td>
<td>80</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>107</td>
<td>140</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>Tilden</td>
<td>55,639</td>
<td>392</td>
<td>Lower EFS</td>
<td>391</td>
<td>60</td>
<td>500</td>
<td>1,023</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>140</td>
<td>60</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>100</td>
<td>60</td>
<td>500</td>
<td></td>
</tr>
<tr>
<td>North Tilden</td>
<td>8,787</td>
<td>19</td>
<td>Lower EFS</td>
<td>54</td>
<td>90</td>
<td>500</td>
<td>73</td>
</tr>
<tr>
<td>Catarina</td>
<td>47,194</td>
<td>188</td>
<td>Lower EFS</td>
<td>354</td>
<td>70</td>
<td>400</td>
<td>1,095</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>404</td>
<td>100</td>
<td>600</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>149</td>
<td>100</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td><strong>Permian</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Champarral</td>
<td>21,750</td>
<td>6</td>
<td>Middle Spraberry</td>
<td>120</td>
<td>160</td>
<td>880</td>
<td>487</td>
</tr>
<tr>
<td></td>
<td></td>
<td>1</td>
<td>Lower Spraberry</td>
<td>119</td>
<td>160</td>
<td>880</td>
<td></td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>2</td>
<td>Wolfcamp A</td>
<td>120</td>
<td>160</td>
<td>880</td>
<td></td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>6</td>
<td>Wolfcamp B</td>
<td>119</td>
<td>160</td>
<td>880</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wolfberry Vertical</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Mustang Draw</td>
<td>8,868</td>
<td>0</td>
<td>Middle Spraberry</td>
<td>71</td>
<td>150</td>
<td>880</td>
<td>284</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Lower Spraberry</td>
<td>71</td>
<td>150</td>
<td>880</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wolfcamp A</td>
<td>71</td>
<td>150</td>
<td>880</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wolfcamp B</td>
<td>71</td>
<td>150</td>
<td>880</td>
<td></td>
</tr>
<tr>
<td><strong>United States</strong></td>
<td><strong>Total</strong></td>
<td><strong>153,156</strong></td>
<td><strong>882</strong></td>
<td><strong>2,679</strong></td>
<td></td>
<td></td>
<td><strong>3,561</strong></td>
</tr>
<tr>
<td>Duvernay</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kaybob</td>
<td>25,466</td>
<td>56</td>
<td>Gas Cond</td>
<td>206</td>
<td>220</td>
<td>1,000</td>
<td>262</td>
</tr>
<tr>
<td></td>
<td>114,534</td>
<td>-</td>
<td>Oil</td>
<td>885</td>
<td>220</td>
<td>1,000</td>
<td>885</td>
</tr>
<tr>
<td>Montney</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tupper</td>
<td>102,000</td>
<td>240</td>
<td>Montney</td>
<td>1,291</td>
<td>220</td>
<td>1,000</td>
<td>1,531</td>
</tr>
<tr>
<td>Placid</td>
<td>18,000</td>
<td>44</td>
<td>Montney</td>
<td>115</td>
<td>290</td>
<td>1,300</td>
<td>159</td>
</tr>
<tr>
<td><strong>Canada</strong></td>
<td><strong>Total</strong></td>
<td><strong>260,000</strong></td>
<td><strong>340</strong></td>
<td><strong>2,497</strong></td>
<td></td>
<td></td>
<td><strong>2,837</strong></td>
</tr>
</tbody>
</table>

*As of December 31, 2017