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.
## FY & 4Q 17 Overview

### Achieving High-Margin Production from Diversified Portfolio

- 4Q 17 Production Averaged 168 MBOEPD
- FY 17 Production Averaged 164 MBOEPD
- 4Q 17 Onshore Production Averaged 96 MBOEPD (52% Liquids)
- 4Q 17 Offshore Production Averaged 72 MBOEPD (72% Liquids)
- Offshore Assets Generated Free Cash Flow of > $500 MM FY 17, > $100 MM 4Q 17
- High-Margin Realizations, Oil-Weighted (61% Liquids)

### Driving EBITDA Margins by Lowering Costs

- Achieved LOE of $7.89/BOE FY 17
- Reduced G&A by 21% Q-O-Q to $55 MM
- Competitive Adj EBITDAX/BOE = ~$24
- Invested $976 MM FY 17 in Capital Expenditures
- $1.1 BN Senior Unsecured Guaranteed Revolving Credit Facility with No Borrowings

### Maintaining Shareholder-Focused Strategy

- Living Within Cash Flow, Maintaining ~$1.0 BN Cash on Hand
- Providing Consistent Competitive Dividend Yield of ~3%
- Allocating Capital to Growing North America Onshore Business
- Building High Return, Low-Cost Offshore Projects
- Replenishing Portfolio with Strategic Exploration Opportunities

---

**Long-Term Oil-Weighted Production Growth Within Cash Flow**
Increasing Reserves & Lowering F&D Costs

- Maintaining High-Margin, Oil-Weighted Portfolio
- Organic Reserves Replacement 113%
- Total Reserves Replacement 123%
- 1 Year Cumulative F&D Costs of $13.09/BOE
- 3 Year Cumulative F&D Costs of $14.08/BOE
- Reserve Life Index 11.7 Years, Increased from 10.6 Years

**2017E Proved Reserves**

- Offshore 29%
- Onshore 71%

**Proved Reserves & Reserve Life**

- 2013: 698 MMBOE
- 2014: 37%
- 2015: 34%
- 2016: 7%
- 2017: 3%

*2014 & 2015 Include Impact of Malaysia Self-Down, **2016 Includes Impact of Syncrude Divestiture*
4Q 17 Financial Overview

Adjustments to 4Q 17 Earnings
- Impact of “Tax Cuts & Jobs Act” ($274 MM)
- Foreign Exchange Gains ($22 MM)
- Mark-to-Market Loss on Crude Oil Contract ($20 MM)
- Materials Inventory Write-Down ($14 MM)
- Redetermination Expense ($9 MM)

Balance Sheet (December 31, 2017)
- Low Leverage (2.19 Total Debt/EBITDAX) with ~$2 BN Liquidity & No Near-Term Debt Maturities
- $2.9 BN Total Debt (Including Capital Lease)
- $1.0 BN Cash & Cash Equivalents
- 39% Total Debt / Total Capitalization
- 30% Net Debt / Total Capitalization

Hedge Positions (January 31, 2018)
- 21,000 BPD at US$54.88/BBL, 2018
- 20 MMCFD at Chicago City Gate US$3.51/MCF, Jan – Mar 2018
- 59 MMCFD at AECO C$2.81/MCF, 2018 – 2020

Consolidated Results

<table>
<thead>
<tr>
<th></th>
<th>4Q 2017</th>
<th>4Q 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income (Loss)</td>
<td>(287)</td>
<td>(64)</td>
</tr>
<tr>
<td>$/Diluted Share</td>
<td>(1.66)</td>
<td>(0.37)</td>
</tr>
</tbody>
</table>

Adjusted Earnings

<table>
<thead>
<tr>
<th></th>
<th>4Q 2017</th>
<th>4Q 2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted Earnings (Loss)</td>
<td>13</td>
<td>(27)</td>
</tr>
<tr>
<td>$/Diluted Share</td>
<td>0.08</td>
<td>(0.16)</td>
</tr>
</tbody>
</table>

Note Maturity Profile

- As of December 31, 2017
- Total Notes Outstanding $BN: 2.8
- Weighted Avg Fixed Coupon: 5.5%
- Weighted Avg Years to Maturity: 8.8
PORTFOLIO REVIEW
Offshore Operations 4Q 17 Highlights

Malaysia
Generated Over $100 MM Free Cash Flow

Sabah
• Kikeh – ESP Pilot Start Up 4Q 17, DTU Gas Lift Project Ongoing

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

Gulf of Mexico (Operated)
99.5% Uptime of Operated Facilities 4Q 17
• Medusa – Preparing for Subsea Well Workover 1Q 18
• Front Runner – Preparing for Rig Program in 4Q 18
Gulf of Mexico Exploration Update

Low-Cost, Near-Term Opportunities that Leverage Existing Infrastructure

Planning for Samurai (GC 432) Appraisal
• Murphy Operator
• Expected Spud 1Q 18
• Mean Gross Resource Potential 75 MMBOE, Resource Upside Potential 200 MMBOE
• Net Well Cost ~$18 MM
• Success Full Cycle IRR > 30%*

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

*Based on WTI $52, Escalated at 5%
International Exploration Update

Mexico Deepwater
Block 5
- Murphy 30% WI, Operator
- Reviewing Newly Processed WAz Seismic, Confirms Multiple Prospects
- 1+ BBOE Gross, 300+ MMBOE Net Recoverable Resource Potential on Block
- 4Q 18 Target Spud Date, Net Well Cost ~$15 MM, Mean Gross Resource Potential 180 MMBOE

Vietnam Cuu Long Basin
Block 15-1/05
- Murphy 35% WI, Non-Op – Working to Become Operator & Increase to 40% WI
- Progressing LDV Field Development Plan, On Track for Declaration of Commerciality in 2018
- Planning to Drill LDT Prospect in 2018 – Mean Gross Resource Potential 30 MMBOE + Upside

Australia Vulcan Basin
Blocks AC/P-21, AC/P-57, AC/P-58, AC/P-59
- Block AC/P-21 – Completed Farm-In, Murphy 40% WI, Non-Op, 3D Seismic Acquisition Ongoing
- Blocks AC/P-57/58/59 – Murphy 60% WI, Farm-Out Process Ongoing to Lower WI
- Multiple 100 MMBOE Prospects for Basin
Multi-Year Global Exploration Plan

Renewed Exploration Portfolio with Low-Cost Entries & Near, Mid & Long-Term Opportunities

Substantial Resource Potential
- Net Unrisked Resource Potential of ~700 MMBOE, Upside Potential ~1.8 BBOE
- Net Risked Resource Potential of ~200 MMBOE

Measured Drilling Approach
- Appropriate WI Opportunities Within Our Focus Areas – Target 35% WI
- Plan to Drill 3 to 4 Wells per Year
- Exploration Drilling CAPEX Target of ~$50 MM per Year Net

Needle-Moving Economic Prospects
- Risked F&D of $12.00
- Risked NPV/BOE of $4.00

<table>
<thead>
<tr>
<th>Offshore Exploration Drilling Plan</th>
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</thead>
<tbody>
<tr>
<td>2018</td>
</tr>
<tr>
<td>-------</td>
</tr>
<tr>
<td>United States</td>
</tr>
<tr>
<td>Mexico</td>
</tr>
<tr>
<td>Brazil</td>
</tr>
<tr>
<td>Australia</td>
</tr>
<tr>
<td>Vietnam</td>
</tr>
<tr>
<td>Malaysia</td>
</tr>
</tbody>
</table>
US Onshore Operations 4Q 17 Highlights

Eagle Ford Shale
- Well Delivery – 78 Wells Online FY 17
- 18 New Wells Online 4Q 17
  - 3 Karnes – 1 Upper EFS, 2 Austin Chalk, Average IP30 1,184 BOEPD per Well
  - 15 Catarina – 13 Lower EFS, 2 Upper EFS, Average IP30 1,095 BOEPD per Well
- 4Q 17 OPEX $6.70/BOE, Record Low – Reduced OPEX by 20% Q-O-Q
- 179% 2017 Organic Reserves Replacement

Midland Basin
- 2 Wells Online 4Q 17, Currently Flowing Back
  - 1 Well in Wolfcamp B
  - 1 Well in Lower Spraberry
Eagle Ford Shale 4Q 17 Highlights

Drilled Murphy Record Lateral Length Well in Catarina, >12,000 ft

IP30 Substantial Improvement in Catarina
- Enhanced Spacing and Frac Designs, Catarina Cluster Spacing Optimized by Area
- Optimized Flowback Techniques
- Co-Development of Upper EFS & Austin Chalk Along with Lower EFS

Catarina Cumulative Production – Online December 2017

- Catarina IP30 Improvement
  - >150% Improvement

- Catarina Cumulative Production
  - 600 MBOE
  - 641 MBOE

- Days on Production
  - 0 to 45

- Cumulative Gross 2-Stream, MBOE
  - 0 to 35

- Average IP30 BOEPD
  - 392 to 983

- Years
  - 2013 to 2017
Tupper Montney 4Q 17 Highlights

Top Tier North American Dry Natural Gas Play

Recent Activity
• a-23 Pad (5 Wells) – 4Q 17 Online, Avg Lateral Length > 10,000 ft, Facility-Constrained Production on Pad, 40 MMCFD
• 15-08 Pad (5 Wells) – Exceeding 18 BCF Type Curve, 3 Upper & 2 Middle Montney

4Q 17 Netback C$2.49/MCF vs AECO Spot C$1.96/MCF
• Full Cycle Break-Even < C$2.00/MCF AECO

AECO Spot Price Volatility
• Addressing with Hedging & Pricing Diversification, 60% of 2018 Production Non-AECO Priced

Expansion Project – Progressing FEED for 2018 Sanction
• Break-Even < C$2.00/MCF AECO

Mitigating AECO Exposure – 2018 Montney Natural Gas Sales

*Source: Tudor, Pickering, Holt & Co.
Kaybob Duvernay 4Q 17 Highlights

Increased Production 31% from 4Q 16 to 4Q 17

Drilling Pacesetter Wells
- Increased Feet per Day by 56% from 2016 to 2017
- Lowered Cost per Foot by 21% from 2016 to 2017

Appraisal Wells Update – Online 4Q 17
- 16-18 Pad (1 Well) – Oil
  - IP30 550 BOEPD (87% Liquids), Facility-Constrained
- 05-29 Pad (2 Wells) – Oil
  - 05-29B IP30 890 BOEPD (74% Liquids)
  - 05-29C IP30 1,190 BOEPD (72% Liquids)
Kaybob Duvernay 2018 Plan

2018 Appraisal & Development Plan
• Drill 17 Wells, Online 23 Wells
• Contingent Drill 7 Wells, Online 2 Wells
• Move Kaybob West & Saxon into Development Mode
• Learnings: Fit for Purpose Rigs, Optimizing Completion Design via Early Well Trials, Gaining Efficiencies by Partnering with Pumping Company

<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>B</td>
<td>15-16</td>
<td>2</td>
<td>Condensate 1Q 2018</td>
</tr>
<tr>
<td>C</td>
<td>12-29</td>
<td>2</td>
<td>Oil 1Q 2018</td>
</tr>
<tr>
<td>D</td>
<td>16-03</td>
<td>3</td>
<td>Condensate 2Q 2018</td>
</tr>
<tr>
<td>E</td>
<td>11-14</td>
<td>5</td>
<td>Condensate 3Q 2018</td>
</tr>
<tr>
<td>F</td>
<td>03-33</td>
<td>4</td>
<td>Oil 3Q 2018</td>
</tr>
<tr>
<td>G</td>
<td>16-14</td>
<td>4</td>
<td>Oil 4Q 2018</td>
</tr>
<tr>
<td>H</td>
<td>16-25</td>
<td>1</td>
<td>Oil 4Q 2018</td>
</tr>
<tr>
<td>I</td>
<td>04-21</td>
<td>1</td>
<td>Oil 4Q 2018</td>
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<tr>
<td>J*</td>
<td>16-18</td>
<td>1</td>
<td>Oil 4Q 2018</td>
</tr>
<tr>
<td>K*</td>
<td>11-12</td>
<td>1</td>
<td>Oil 4Q 2018</td>
</tr>
</tbody>
</table>

*2018 Contingent Well Program
LOOKING AHEAD
2018 Plan

2018 Annual Capex Guidance $1.056 BN
- $650 MM Allocated to NA Onshore Unconventional
- 88% Allocated to Field Development & Development Drilling
- Includes ~$125 MM CAPEX for Long-Term Offshore Projects
  - Dalmatian Subsea Pump, Online 4Q 2018
  - Kikeh DTU Gas Lift, Online 3Q 2018
  - Rotan Block H FLNG, Online 4Q 2020
  - Vietnam Success Payments, Online 4Q 2021

2018 Production Guidance
- 1Q 18 Guidance 164 – 168 MBOEPD, 59% Liquids
  - 4 Eagle Ford Shale Wells Online
  - 11 Kaybob Duvernay/Placid Montney Wells Online
  - Operated Impacts
    - Eagle Ford Shale Offset Frac Impacts
    - GOM Medusa Workover
  - Non-Operated Impacts
    - Habanero & Kodiak Delays
- FY 18 Guidance 166 – 170 MBOEPD, 59% Liquids

Guidance Assumes WTI $52 to $55/BBL & HH $2.90 to $3.00/MCF
Paying Our Way & Living Within Cash Flow

- Protected Our Shareholders by Not Issuing Equity During Downturn
- Maintained Strong Balance Sheet with Measured Spending & Asset Sales
- Proven Track Record of Financial Discipline
- Paid Over $800 MM Dividend to Shareholders 2014 – 2017
- Defined Program to Grow Production & Reserves Within Cash Flow Going Forward

**Peer Adjusted Free Cash Flow & Equity Issuance Comparison 2014 – 3Q 2017**
Multi-Year Plan

- 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
- Maintaining Total Debt/EBITDAX ≤ 2.0
- Resilience to Downside & Considerable Upside at Higher Oil Prices

<table>
<thead>
<tr>
<th>Price</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
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<tbody>
<tr>
<td>WTI</td>
<td>52.00</td>
<td>54.60</td>
<td>57.33</td>
<td>60.20</td>
<td>63.21</td>
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<tr>
<td>Brent</td>
<td>55.50</td>
<td>58.10</td>
<td>60.83</td>
<td>63.70</td>
<td>66.71</td>
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<tr>
<td>HH</td>
<td>3.00</td>
<td>2.81</td>
<td>2.86</td>
<td>2.92</td>
<td>2.98</td>
</tr>
</tbody>
</table>

±5% Production

*Includes Brunei
Takeaways

Growing Production with Disciplined Capital Allocation

Achieving High Cash Margins from Diverse, Oil-Weighted Portfolio

Focusing on Continued Cost Reductions

Continuing to Return Cash to Shareholders with Current Dividend Policy

Positioning Company for 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>
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<tr>
<th></th>
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<tbody>
<tr>
<td>Net loss</td>
<td>(286.8)</td>
<td>(63.9)</td>
</tr>
<tr>
<td>Discontinued operations loss</td>
<td>2.0</td>
<td>1.1</td>
</tr>
<tr>
<td>Impact of tax reform</td>
<td>274.3</td>
<td>-</td>
</tr>
<tr>
<td>Loss on sale of assets</td>
<td>2.5</td>
<td>-</td>
</tr>
<tr>
<td>Foreign exchange gains</td>
<td>(22.4)</td>
<td>(19.4)</td>
</tr>
<tr>
<td>Tax benefits on investments in foreign areas</td>
<td>-</td>
<td>(5.9)</td>
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<tr>
<td>Materials inventory loss</td>
<td>14.1</td>
<td>9.0</td>
</tr>
<tr>
<td>Redetermination expense</td>
<td>9.3</td>
<td>24.2</td>
</tr>
<tr>
<td>Mark-to-market loss on crude oil derivate contracts</td>
<td>20.0</td>
<td>28.5</td>
</tr>
<tr>
<td>Oil Insurance Limited dividends</td>
<td>-</td>
<td>(2.2)</td>
</tr>
<tr>
<td>Environmental provisions</td>
<td>-</td>
<td>4.5</td>
</tr>
<tr>
<td>Deepwater rig contract exit benefit</td>
<td>-</td>
<td>(2.8)</td>
</tr>
<tr>
<td><strong>Adjusted Earnings (Loss)</strong></td>
<td><strong>13.0</strong></td>
<td><strong>(26.9)</strong></td>
</tr>
</tbody>
</table>
Non-GAAP Reconciliation

**EBITDA and EBITDAX**

Murphy defines EBITDA as income from continuing operations before income taxes, depreciation, depletion and amortization (DD&A), net interest expense, and impairment expense. 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 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>
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<tr>
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<tbody>
<tr>
<td>Net income (loss) GAAP</td>
<td>(286.8)</td>
<td>(63.9)</td>
</tr>
<tr>
<td>Discontinued operations loss</td>
<td>2.0</td>
<td>1.1</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>287.1</td>
<td>(17.3)</td>
</tr>
<tr>
<td>Interest expense, net of interest capitalized</td>
<td>43.4</td>
<td>44.3</td>
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<tr>
<td>DD&amp;A expense</td>
<td>242.9</td>
<td>256.8</td>
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<tr>
<td><strong>Consolidated EBITDA (Non-GAAP)</strong>*</td>
<td><strong>288.6</strong></td>
<td><strong>221.0</strong></td>
</tr>
<tr>
<td>Exploration Expense</td>
<td>45.5</td>
<td>18.0</td>
</tr>
<tr>
<td><strong>Consolidated EBITDAX (Non-GAAP)</strong>*</td>
<td><strong>334.1</strong></td>
<td><strong>239.0</strong></td>
</tr>
</tbody>
</table>

*EBITDA and EBITDAX for the three months ended December 31, 2017 included certain pretax items that decreased both amounts by $21.1 million.
ADJUSTED EBITDAX
Murphy defines Adjusted EBITDAX as income from continuing operations before income taxes, exploration expenses, depreciation, depletion and amortization (DD&A), net interest 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>
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<tbody>
<tr>
<td><strong>Consolidated EBITDAX</strong></td>
<td>334.1</td>
<td>239.0</td>
</tr>
<tr>
<td>Mark-to-market loss on crude oil derivative contracts</td>
<td>30.8</td>
<td>43.8</td>
</tr>
<tr>
<td>Foreign exchange gains</td>
<td>(24.0)</td>
<td>(23.3)</td>
</tr>
<tr>
<td>Accretion of asset retirement obligations</td>
<td>11.0</td>
<td>11.2</td>
</tr>
<tr>
<td>Other</td>
<td>3.3</td>
<td>1.4</td>
</tr>
<tr>
<td><strong>Adjusted EBITDAX (Non-GAAP)</strong></td>
<td><strong>355.2</strong></td>
<td><strong>272.1</strong></td>
</tr>
<tr>
<td>Total barrels of oil equivalents sold (boe)</td>
<td>15,106.4</td>
<td>15,518.5</td>
</tr>
<tr>
<td><strong>Adjusted EBITDAX per boe (Non-GAAP)</strong></td>
<td><strong>23.51</strong></td>
<td><strong>17.53</strong></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, 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)

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

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 – 1Q 2018

### Guidance 1Q

<table>
<thead>
<tr>
<th>1Q Production:</th>
<th>1Q 2018 Liquids (BOPD)</th>
<th>1Q 2018 Gas (MCFD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>US Onshore</td>
<td>40,500</td>
<td>30,500</td>
</tr>
<tr>
<td>Gulf of Mexico</td>
<td>11,750</td>
<td>11,000</td>
</tr>
<tr>
<td>Canada – Tupper Montney</td>
<td>-</td>
<td>235,000</td>
</tr>
<tr>
<td>Kaybob Duvernay &amp; Placid Montney</td>
<td>4,750</td>
<td>25,500</td>
</tr>
<tr>
<td>Offshore</td>
<td>8,250</td>
<td>-</td>
</tr>
<tr>
<td>Malaysia – Sarawak</td>
<td>13,500</td>
<td>104,500</td>
</tr>
<tr>
<td>Block K/Brunei</td>
<td>18,250</td>
<td>7,500</td>
</tr>
</tbody>
</table>

| 1Q Production Volume (BOEPD)     | 164,000 – 168,000      |
| 1Q Sales Volume (BOEPD)          | 161,000 – 165,000      |
| 1Q Exploration Expense ($MM)     | $30.0                  |
| Full Year 2018 Production (BOEPD)| 166,000 – 170,000      |
| Full Year 2018 Capex ($MM)       | $1,056.0               |
| 1Q Expected Realized Prices ($/BBL)|                       |
| Malaysia – Block K               | $64.20                 |
| Sarawak Oil                      | $62.95                 |
| Sarawak Gas                      | $3.80                  |
# 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>1/1/2018</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>1/1/2018</td>
<td>12/31/2020</td>
</tr>
<tr>
<td>Duvernay</td>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales</td>
<td>20</td>
<td>US$3.51*</td>
<td>1/1/2018</td>
<td>3/31/2018</td>
</tr>
</tbody>
</table>

*Title transfer at Alberta Alliance pipeline. Sale price fixed and transported to Chicago Gate.*
# NA Onshore Running Room

## Three Main Unconventional Plays: Eagle Ford Shale, Duvernay & Montney

- **Significant Multi-Year Inventory with Stacked Pay Potential Upside**

## Permian

- **Developing Unconventional Play**
- **Significant Stacked Pay Potential Upside**

*As of December 31, 2017*