Cautionary Statement & Investor Relations Contacts

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 PMEAN 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 within the meaning of 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 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 U.S. Securities and Exchange Commission (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 and from Murphy Oil Corporation’s website at http://ir.murphyoilcorp.com. Murphy Oil Corporation undertakes no duty to publicly update or revise any forward-looking statements.

Non-GAAP Financial Measures – This presentation refers to certain forward looking non-GAAP measures such as future “Free Cash Flow” and future “EBITDA”. Definitions of these measures are included in the appendix.

Kelly Whitley
VP, Investor Relations & Communications
281-675-9107
kelly_whitley@murphyoilcorp.com

Bryan Arciero
Sr. Investor Relations Advisor
281-675-9339
bryan_arciero@murphyoilcorp.com

Megan Larson
Sr. Investor Relations Analyst
281-675-9470
megan_larson@murphyoilcorp.com

January 2020
www.murphyoilcorp.com
NYSE: MUR
Agenda

01 COMPANY UPDATE
02 ONSHORE PORTFOLIO UPDATE
03 OFFSHORE PORTFOLIO UPDATE
04 EXPLORATION UPDATE
05 LOOKING AHEAD
A History of Excellence

• Long corporate history, IPO 1956
• Global offshore and North American onshore portfolio
• Oil-weighted assets drive high margins
• Exploration renaissance in focus areas
• Consistent cash flows from long-term offshore assets
• Growing unconventional assets in North American onshore
• Low leverage with appropriate liquidity and strong balance sheet
• History of shareholder-focused dividend policy
Murphy at a Glance

Post-Transaction Reserves*

- **By Area**
  - 760 MMBOE
  - 27% US Onshore
  - 37% Canada Onshore
  - 36% NA Offshore

- **By Product Mix**
  - 62% Liquids-Weighted
  - 38% Natural gas
  - 8% NGLs

3Q 2019 Production

- **By Area**
  - 192 MBOEPD
  - 44% US Onshore
  - 26% Canada Onshore
  - 29% NA Offshore

- **By Product Mix**
  - 66% Liquids-Weighted
  - 34% Natural gas
  - 7% NGLs

* Based on internal estimates as of January 1, 2019 using year-end SEC pricing. Includes MP GOM (excluding non-controlling interest) and LLOG asset acquisitions and Malaysia divestiture, and excludes Brunei (asset held for sale).
Value-Adding Transformation

2014 – 2015
Repositioning Portfolio Post-Spin; Streamlining Assets

2014
Sell-Down
30% Malaysia
$2.0 BN

2016
Divested Montney Midstream
Montney
$412 MM

2016
Acquired Kaybob Duvernay & Placid Montney
$206 MM

2016 – 2017
Stabilizing & Rebuilding; Strengthening Balance Sheet Without Issuing Equity

2016
Divested Syncrude
$730 MM

2017
Divested Heavy Oil
$51 MM

2016
Divested Malaysia
$1.375 BN

2018 – 2019
Reshaping Portfolio; Growing Oil-Weighted Assets with Free Cash Flow Generation

2018
Transaction with Petrobras Gulf of Mexico
Gulf of Mexico
$795 MM

2018
Acquired LLOG Gulf of Mexico Assets
$1.375 BN

2019
Acquired LLOG Gulf of Mexico Assets
$1.375 BN

2019
Divested Malaysia
$2.127 BN
Achieving Premium Oil-Weighted Realizations

>112,000 BBLs/Day
SOLD 3Q 2019

94% SOLD
At Premium
to $56.45 WTI

Eagle Ford Shale

Premium to WTI
3Q 2019

>$2/BBL

EBITDA/BOE
3Q 2019
FIELD-LEVEL

$35/BOE

North America Offshore

>$4/BBL

HLS
+$5.50/BBL

32%

Other

MEH
+$4.57/BBL

36%

Sales Volumes & Differentials

3Q 2019 Total Company

Brent
+$5.55/BBL

36%

Mars
+$4.01/BBL

32%

HLS
+$5.50/BBL

22%

MEH
+$4.57/BBL

6%

Differentials

vs $56.45 WTI

NOTE: Premium to WTI excludes transportation costs
**Achieving High Operating Margins**

- Generating >$50/BBL margins
- Allocating >75% of capital to Eagle Ford Shale and Gulf of Mexico
- Operating efficiencies result in low OPEX
- Timely hedging mitigates cash flow risk

**3Q 2019 Operating Margins $/BBL**

- **Eagle Ford Shale**: $59
- **Gulf of Mexico**: $62

**Operating margin**

**Opex**

**Avg realized price**

**NOTE:** Operating margin calculated as price realizations less operating expenses WTI $56.45/BBL in 3Q 2019.
Long History of Benefitting Shareholders

> $6.3 Billion
> Returned to Shareholders
Since 1961

> $4.4 Billion
> Returned to Shareholders
In last 10 years

> $1.6 Billion
in Share Repurchases
2012 – 1H 2019

Free Cash Flow $MM 2019E

Note: FCF = 2019E Median Consensus Cash Flow from Operations less Annual CAPEX (12/31/2019)
Source: FactSet
Peer Group: APA, CHK, CNX, COG, DVN, ECA, HES, MRO, MTDR, NBL, RRC, SM, SWN, WLL, XEC

Dividend Yield

Source: FactSet at 1/6/2020
Peer Group: APA, CHK, CNX, COG, DVN, ECA, HES, MRO, MTDR, NBL, RRC, SM, SWN, WLL
Note: No dividend paid by CHK, CNX, MTDR, SWN, WLL

Cash Paid to Shareholders $MM 1997 - 2019

Source: FactSet at 1/6/2020
Peer Group: APA, CHK, CNX, COG, DVN, ECA, HES, MRO, MTDR, NBL, RRC, SM, SWN, WLL
Note: No dividend paid by CHK, CNX, MTDR, SWN, WLL
Executing Our 2019 Plan

PRODUCING
Oil-Weighted Assets

Produced 192 MBOEPD, ~60% Oil
Produced highest oil volumes since 1Q 2015\(^1\)
Increased Eagle Ford Shale oil production >22% from 2Q 2019
Lowered LOE/BOE by 13% from 2Q 2019 to <$8

GENERATING
High Margin Realizations

94% oil volumes sold at premium to WTI
Adjusted EBITDA $438 MM highest since 4Q 2014
>$24 adj. EBITDA/BOE
>$36 EBITDA/BOE US & Canada offshore\(^2\)
Added oil hedges with 2020 average price >$53 WTI

INCREASING
Capital Returns to Shareholders

Completed $500 MM share buyback program
Delivered 5% dividend yield
Returned >$620 MM to shareholders YTD 2019
Benefitted shareholders within cash flow including sale proceeds

TRANSFORMING
Portfolio for Future Value

Successfully bid on 3 blocks in Brazil's Sergipe-Alagoas Basin
Farmed in to 3 blocks in Brazil's Potiguar Basin
Positioned to produce over 200 MBOEPD in 4Q 2019

BUILDING
Profitable Production

Brought GOM Dalmatian well online at >5,000 BOEPD gross
Completed multiple GOM workover and tie-back projects, first oil 4Q 2019

---

1 Excluding Syncrude and heavy oil
2 Field level
Onshore Portfolio Update
Concentrated Onshore Assets with Repeatable Results

- **Kaybob Duvernay**
  - 11 MBOEPD at 3Q 2019, 58% oil, 69% liquids
  - ~80 total producing wells online

- **Eagle Ford Shale**
  - 51 MBOEPD at 3Q 2019, 80% oil, 91% liquids
  - ~1,005 total producing wells online

- **Tupper Montney**
  - 269 MMCFD at 3Q 2019
  - ~250 total producing wells online

Oil-Weighted Platform Across North America

Well-Positioned for Natural Gas
Significant Running Room in the Eagle Ford Shale

Significant Development Across ~125,000 Net Acres

- 500+ MMBOE total resource potential
- Conservative inter-well spacing, type curves account for parent/child relationship
- Completion designs optimized by pad & well
- Long life asset at low end of cost curve
- Remote operating center with big data focus

Eagle Ford Shale Acreage

Long-Term Plan Well Cadence*

<table>
<thead>
<tr>
<th>Area</th>
<th>Net Acres</th>
<th>Reservoir</th>
<th>Inter-Well Spacing (ft)</th>
<th>Gross Remaining Wells*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Karnes</td>
<td>10,918</td>
<td>Lower EFS</td>
<td>300</td>
<td>121</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>700</td>
<td>159</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>700</td>
<td>108</td>
</tr>
<tr>
<td>Tilden</td>
<td>64,737</td>
<td>Lower EFS</td>
<td>500</td>
<td>388</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>500</td>
<td>140</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>600</td>
<td>100</td>
</tr>
<tr>
<td>Catarina</td>
<td>47,653</td>
<td>Lower EFS</td>
<td>450</td>
<td>292</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Upper EFS</td>
<td>600</td>
<td>354</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Austin Chalk</td>
<td>800</td>
<td>149</td>
</tr>
<tr>
<td>Total</td>
<td>123,308</td>
<td></td>
<td></td>
<td>1,811</td>
</tr>
</tbody>
</table>

* As of December 31, 2018
2019 Well Delivery Plan
- 91 wells online

3Q 2019 51 MBOEPD, 80% Oil, 91% Liquids
- >15% increase in volumes from 2Q 2019
- 25 wells online, 91% liquids
  - 15 Catarina – 11 Lower EFS, 4 Upper EFS
  - 10 Tilden – Lower EFS

4Q 2019, 18 Wells Online
- 8 Tilden – Lower EFS
- 10 Catarina – 9 Lower EFS, 1 Upper EFS

Consistently Increasing EURs
- Improved well targeting
- Optimized completion design
  - Resulting in higher oil cut and IP rates

Achieving Lower OPEX
- <$7/BOE 3Q 2019
- >18% reduction from 2Q 2019

NOTE: EFS = Eagle Ford Shale

Eagle Ford Shale Acreage

EUR per Well MBOE by Year

NOTE: Interquartile range shows difference between 75th and 25th percentile of well EURs
Eagle Ford Shale
Well Outperformance in Tilden and Catarina

Tilden – 10 Tyler Ranch Wells Online
- 10 Lower EFS wells with avg 7,100’ lateral
  - 500’ well spacing
  - Average IP30 of 1,300 BOEPD

Catarina – 11 Stumberg Wells Online
- 9 Lower EFS wells with avg 7,800’ lateral
  - 350’ well spacing
  - Lower EFS wells peak IP 1,400 BOEPD average
- 2 Upper EFS wells with avg 8,800’ lateral
  - 1,200’ well spacing
  - Performing to type curve
Kaybob Duvernay
Scalable Assets For Future Growth

Oil-Weighted Production from Low Cost Assets

• Approaching completion of retention drilling
• Optimizing development plan and lateral lengths
• Continuing outperformance with high rate wells
• Targeting $6.5 MM per well drilling and completions costs

<table>
<thead>
<tr>
<th>Area</th>
<th>Net Acres</th>
<th>Inter-Well Spacing (ft)</th>
<th>Remaining Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Two Creeks</td>
<td>34,336</td>
<td>984</td>
<td>123</td>
</tr>
<tr>
<td>Kaybob East</td>
<td>36,400</td>
<td>984</td>
<td>182</td>
</tr>
<tr>
<td>Kaybob West</td>
<td>25,760</td>
<td>984</td>
<td>119</td>
</tr>
<tr>
<td>Kaybob North</td>
<td>31,360</td>
<td>984</td>
<td>129</td>
</tr>
<tr>
<td>Simonette</td>
<td>29,715</td>
<td>984</td>
<td>82</td>
</tr>
<tr>
<td>Saxon</td>
<td>12,746</td>
<td>984</td>
<td>37</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>170,317</strong></td>
<td></td>
<td><strong>672</strong></td>
</tr>
</tbody>
</table>
2019 Well Delivery Plan Complete
- 10 wells online in Kaybob Duvernay

3Q 2019 Results
- Kaybob Duvernay: 11 MBOEPD, 69% liquids
  - >18% increase in volumes from 2Q 2019

Kaybob Duvernay Land Retention Plan
- Drilling 16 wells in 2019, completions in 2020

2019 Online Wells

<table>
<thead>
<tr>
<th>Area</th>
<th>Pad</th>
<th>Wells Online</th>
<th>IP30 (BOEPD)</th>
<th>Liquids</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simonette</td>
<td>08-03</td>
<td>3</td>
<td>1,400*</td>
<td>86%</td>
</tr>
<tr>
<td>Kaybob North</td>
<td>05-23</td>
<td>2</td>
<td>1,054</td>
<td>86%</td>
</tr>
<tr>
<td>Two Creeks</td>
<td>05-19</td>
<td>2</td>
<td>651*</td>
<td>91%</td>
</tr>
<tr>
<td>Two Creeks</td>
<td>16-29</td>
<td>2</td>
<td>858*</td>
<td>91%</td>
</tr>
<tr>
<td>Kaybob North</td>
<td>16-25</td>
<td>1</td>
<td>834*</td>
<td>85%</td>
</tr>
</tbody>
</table>

* Well volumes constrained due to current facility limitations.

Strong Results in Kaybob Duvernay
- Recent well performance mirrors Tilden Lower EFS
  - Leveraged learnings to optimize completions design, resulting in EUR improvement
  - High-grading locations across contiguous acreage
  - Drilled pacesetter well: 12.5 days, $2.4 MM
    - In line with Eagle Ford Shale drilling rates
    - 9,700' lateral length

2019 Kaybob New Well Performance vs Eagle Ford Shale – Tilden LEFS

Cum MBOE

Days Online

Cum MBOE EUR

2019 Kaybob Wells Average

Tyler Ranch LEFS Average Type Curve
2019 Well Delivery Plan Complete
- 8 wells online

3Q 2019 45 MBOEPD, 100% Natural Gas
- >20% increase in volumes from 2Q 2019
- New wells trending in line with 18 BCF type curve

Successful AECO Price Mitigation
- Realized 3Q 2019 C$1.61/MCF* vs AECO realized average of C$0.99/MCF
- Projected FY19 C$2.26/MCF* vs AECO realized average of C$1.71/MCF

* C$0.27 transportation cost to AECO not subtracted

[Diagram showing Mitigating AECO Exposure]

Tupper Montney Natural Gas Realizations 3Q 2019 $CAD/MCF

- MUR AECO Realized**
- Hedge Uplift
- Diversification Uplift
- Realized Price

* C$0.27 of transportation cost not subtracted
Offshore Portfolio Update
Revitalized Portfolio

- Top 5 Gulf of Mexico operator by production
- Achieves high margin EBITDA/BOE
- Generating ongoing synergies from acquisitions
- Long runway for further development projects

<table>
<thead>
<tr>
<th>PRODUCING ASSETS</th>
<th>Operator</th>
<th>Murphy WI(^1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cascade</td>
<td>Murphy</td>
<td>80%</td>
</tr>
<tr>
<td>Chinook</td>
<td>Murphy</td>
<td>53%</td>
</tr>
<tr>
<td>Clipper</td>
<td>Murphy</td>
<td>80%</td>
</tr>
<tr>
<td>Cottonwood</td>
<td>Murphy</td>
<td>80%</td>
</tr>
<tr>
<td>Dalmatian</td>
<td>Murphy</td>
<td>56%</td>
</tr>
<tr>
<td>Front Runner</td>
<td>Murphy</td>
<td>50%</td>
</tr>
<tr>
<td>Habanero</td>
<td>Shell</td>
<td>27%</td>
</tr>
<tr>
<td>Kodiak</td>
<td>Kosmos</td>
<td>48%</td>
</tr>
<tr>
<td>Lucius</td>
<td>Anadarko</td>
<td>9%</td>
</tr>
<tr>
<td>Marmalard</td>
<td>Murphy</td>
<td>27%</td>
</tr>
<tr>
<td>Marmalard East</td>
<td>Murphy</td>
<td>70%</td>
</tr>
<tr>
<td>Medusa</td>
<td>Murphy</td>
<td>48%</td>
</tr>
<tr>
<td>Neidermeyer</td>
<td>Murphy</td>
<td>53%</td>
</tr>
<tr>
<td>Powerball</td>
<td>Murphy</td>
<td>75%</td>
</tr>
<tr>
<td>Son of Bluto II</td>
<td>Murphy</td>
<td>27%</td>
</tr>
<tr>
<td>St. Malo</td>
<td>Chevron</td>
<td>20%</td>
</tr>
<tr>
<td>Tahoe</td>
<td>W&amp;T</td>
<td>24%</td>
</tr>
<tr>
<td>Thunder Hawk</td>
<td>Murphy</td>
<td>50%</td>
</tr>
</tbody>
</table>

Note: Anadarko is a wholly-owned subsidiary of Occidental Petroleum
\(^1\) Excluding noncontrolling interest
3Q 2019 Production 78 MBOEPD, 85% Liquids
  • Operated production exceeded guidance

Dalmatian DC4 #2 Well
  • Well drilled and completed, online 3Q 2019
  • Online rate ~5,400 BOEPD gross

Nearly Headless Nick
  • Completing well tie-in activities, online 4Q 2019

Medusa Rig Program
  • Well workover complete, rig demobilized

King’s Quay Floating Production System
  • Construction underway
  • Pursuing sell-down opportunities

St. Malo Waterflood Project Sanctioned
  • Forecast to increase total EUR by 30 – 35 MMBOE\(^1\) net to Murphy

---

1 Contingent resources
Short Term Project Update

- Working through planning and engineering
  - 3 tie-back projects
  - 1 well workover

Long Term Project Update

- Khaleesi / Mormont subsea engineering and construction contracts to be awarded in near-term
- Samurai pre-FEED work ongoing
  - Contracts bid jointly with Khaleesi / Mormont

### Short Term Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Planning &amp; Engineering</th>
<th>Drilling &amp; Completions</th>
<th>Subsea Tie-In</th>
<th>First Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dalmatian DC4 #2</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
</tr>
<tr>
<td>Nearly Headless Nick</td>
<td>✔</td>
<td>✔</td>
<td>✔</td>
<td>4Q 2019</td>
</tr>
<tr>
<td>Medusa</td>
<td>✔</td>
<td>✔</td>
<td>n/a</td>
<td>4Q 2019</td>
</tr>
<tr>
<td>Cottonwood</td>
<td>Ongoing</td>
<td>1Q 2020^1</td>
<td>n/a</td>
<td>2Q 2020</td>
</tr>
<tr>
<td>Calliope</td>
<td>Ongoing</td>
<td>✔</td>
<td>3Q 2020</td>
<td>4Q 2020</td>
</tr>
<tr>
<td>Ourse</td>
<td>Ongoing</td>
<td>3Q 2020(^2)</td>
<td>1H 2021</td>
<td>2H 2021</td>
</tr>
<tr>
<td>Son of Bluto II</td>
<td>Ongoing</td>
<td></td>
<td>2H 2021(^2)</td>
<td>4Q 2021</td>
</tr>
</tbody>
</table>

1 Well workover. No drilling/completions activities.
2 Completion only. Well previously drilled. Khaleesi / Mormont 4 of 5 wells previously drilled.

### Long Term Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Planning &amp; Engineering</th>
<th>Drilling &amp; Completions</th>
<th>Subsea Tie-In</th>
<th>First Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Khaleesi / Mormont</td>
<td>Ongoing</td>
<td>4Q 2020 – 4Q 2021(^2)</td>
<td>2021</td>
<td>1H 2022</td>
</tr>
<tr>
<td>Samurai</td>
<td>Ongoing</td>
<td>4Q 2020 – 4Q 2021</td>
<td>2021</td>
<td>1H 2022</td>
</tr>
<tr>
<td>St. Malo Waterflood</td>
<td>Ongoing</td>
<td>2Q 2020 – 2Q 2021</td>
<td>2022</td>
<td>2023</td>
</tr>
</tbody>
</table>
Gulf of Mexico Short Cycle Projects

<table>
<thead>
<tr>
<th>New Wells</th>
<th>Completions &amp; Tie-Backs</th>
<th>Workovers</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dalmatian DC4 #2</td>
<td>Nearly Headless Nick</td>
<td>Cottonwood</td>
</tr>
<tr>
<td>Son of Bluto II</td>
<td>Ourse</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Calliope</td>
<td></td>
</tr>
</tbody>
</table>

21 MMBOE Total Net Resources

$7.50/BBL CAPEX

>80% IRR Average Project

WTI $55/BBL, 2019-2023

Gulf of Mexico Short Cycle Capital Projects Deliver Accelerated Returns

**Development Timeline**

- 2019
  - Dalmatian
  - Nearly Headless Nick
  - Son of Bluto II
  - Ourse
  - Cottonwood

- 2020
  - Dalmatian
  - Nearly Headless Nick
  - Son of Bluto II
  - Ourse
  - Calliope
  - Cottonwood

**Net CAPEX $MM**

Production volumes may vary based on timing and performance.
Production volumes, reserves and financial amounts exclude non-controlling interest.

**Net Production MBOEPD**

<table>
<thead>
<tr>
<th>Project</th>
<th>2019</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
<th>2023</th>
<th>2024</th>
<th>2025</th>
<th>2026</th>
<th>2027</th>
<th>2028</th>
<th>2029</th>
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</thead>
<tbody>
<tr>
<td>Dalmatian</td>
<td>21</td>
<td>30</td>
<td>40</td>
<td>50</td>
<td>60</td>
<td>70</td>
<td>80</td>
<td>90</td>
<td>100</td>
<td>110</td>
<td>120</td>
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<tr>
<td>Cottonwood</td>
<td>17</td>
<td>20</td>
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<td>35</td>
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<td>50</td>
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<tr>
<td>Nearly Headless Nick</td>
<td>15</td>
<td>22</td>
<td>28</td>
<td>35</td>
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<td>45</td>
<td>50</td>
<td>55</td>
<td>60</td>
<td>65</td>
<td>70</td>
</tr>
<tr>
<td>Son of Bluto II</td>
<td>10</td>
<td>15</td>
<td>20</td>
<td>25</td>
<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
<td>55</td>
<td>60</td>
</tr>
<tr>
<td>Calliope</td>
<td>5</td>
<td>10</td>
<td>15</td>
<td>20</td>
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<td>30</td>
<td>35</td>
<td>40</td>
<td>45</td>
<td>50</td>
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</tr>
<tr>
<td>Ourse</td>
<td>3</td>
<td>5</td>
<td>8</td>
<td>10</td>
<td>12</td>
<td>14</td>
<td>16</td>
<td>18</td>
<td>20</td>
<td>22</td>
<td>24</td>
</tr>
</tbody>
</table>

Production Generated through 2040
Gulf of Mexico
Investing in Long Term High-Margin Projects

Khaleesi / Mormont
- Gross resource ~165 MMBOE, 90% liquids
- 7 development wells planned – 4 previously drilled
- IRR >30%, NPV >$300 MM

Samurai
- Gross resource ~60 MMBOE, 90% liquids
  - Potential upside ~15 MMBOE
  - 4 development wells planned
  - IRR >35%, NPV >$200 MM

WTI $55/BBL, 2019-2023

Development Timeline

Net CAPEX $MM

Production Timeline

Net Production MBOEPD

Production volumes may vary based on timing and performance
Production volumes, reserves and financial amounts exclude non-controlling interest
Gulf of Mexico
Generating Long Term Free Cash Flow

Capital Commitments Support Long Term Growth

- Sanctioned St. Malo waterflood project 3Q 2019
- Maintaining $325 MM average CAPEX 2019 – 2023 assuming King’s Quay sell down
- Affirming 2019 CAPEX guidance
- Producing 85 MBOEPD average from 2019 – 2023
- Delivering sustainable cash flow from large inventory of development projects

CAPEX from Major Projects include Samurai and Khaleesi / Mormont
St. Malo waterflood CAPEX includes $50 MM carry for Petrobras Americas Inc.
Production volumes, sales volumes, reserves and financial amounts exclude non-controlling interest, unless otherwise stated.

2019 – 2023 Estimated Gulf of Mexico Production MBOEPD

2019E Annualized Production assumes full year impact of acquired assets in LLOG transaction.
Production from Major Projects includes St. Malo waterflood, Samurai and Khaleesi / Mormont.
Exploration Update
Exploration Strategy Overview

Focused & Meaningful

- Four primary exploration areas
- 3 to 5 exploration wells per year
- ~$100 MM/year

Reduced Risk

- Proven oil provinces
- Targeting appropriate working interest
- Leveraging strategic partnerships

Strategic Themes

- Consistent US Gulf of Mexico program
- Field extension and exploration in Vietnam
- Company-making potential from Brazil and Mexico
- Targeting <$12/BBL full-cycle finding and development cost
Asset Overview

• Murphy 20%, ExxonMobil 50% (Op), Enauta Energia S.A. 30%
• Hold WI in 6 blocks, spanning ~1.1 MM acres
• >1.2 BN BOE reserves discovered nearby
• Successfully bid on 3 adjacent blocks in 3Q 2019
  • Blocks SEAL-M-505, SEAL-M-575 and SEAL-M-637
  • Added ~560,000 acres to position

Continuing to Evaluate Data

• Progressing seismic program and interpretation
• Providing long-term exploration upside
Asset Overview

• Murphy 30% WI, Wintershall Dea 70% (Op)
• Farm-in agreement to 3 blocks signed 3Q 2019
  • Blocks POT-W-857, POT-W-863 and POT-W-865
  • Total ~774,000 gross acres
• Proven oil basin in proximity to Pitu oil discovery
• Independent to Murphy’s position in Sergipe-Alagoas Basin
• 3D seismic program in progress
Block 5 Overview

- Increased working interest to 40% at low cost
  - Murphy 40% (Op), Petronas 30%, DEA 30%
- 34 leads / prospects
- Mean to upward gross resource potential:
  - 800 MMBO – 2,000 MMBO
- Planning additional exploration program in 2020

Cholula 1-EXP Highlights

- ~$12 MM net drilling costs
- Drilled to total depth (TD) of 8,825 feet
- Discovered 185 feet net hydrocarbon pay
  - Validates block potential
  - De-risks Upper Miocene play in SE corner of Block 5
- ~200 MMBOE of resources within tie-back distance
Asset Overview

• Murphy 40% (Op), PVEP 35%, SKI 25%
• >400 MMBOE remaining resource potential on initial block (15-1/05)

Block 15-1/05 – Lac Da Vang (LDV) Field

• Received Prime Minister approval for LDV field outline development plan
• Commenced front-end engineering design work
• Continuing post-well analysis of LDT-1X discovery well
  • Potential to add bolt-on resources to LDV field development

Block 15-2/17

• Received Prime Minister approval on production sharing contract
• Formal contract signed 4Q 2019
Looking Ahead
## Executing 2019 Goals

<table>
<thead>
<tr>
<th>POST-MALAYSIA TARGETS</th>
<th>ACHIEVING GOALS</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>$300 MILLION</strong></td>
<td>ACCOMPLISHING SHARE REPURCHASE</td>
</tr>
<tr>
<td><strong>200 MBOEPD</strong></td>
<td>DELIVERING 4Q 2019 PRODUCTION RATE</td>
</tr>
<tr>
<td><strong>68%</strong></td>
<td>GENERATING LIQUIDS-WEIGHTED PRODUCTION</td>
</tr>
<tr>
<td><strong>&gt; 95%</strong></td>
<td>REALIZING SALES VOLUMES AT PREMIUM TO WTI</td>
</tr>
</tbody>
</table>

All while maintaining our cash position 2018 - 2019
Executing on Long-Term Plan

Maintaining >65% Liquids Production Weighting
- Plan flexible to maintain cash flow / CAPEX parity including dividend

US Onshore – Focusing on Oil-Weighted Growth

Canada Onshore – Scalable Based on Market Conditions
- Focused on lease retention

NA Offshore – Maintaining Current Production
- Consistent free cash flow business
- Short-cycle tiebacks and development projects at existing facilities
- St. Malo waterflood, Khaleesi / Mormont and Samurai projects included

Exploration – Dedicated Strategy
- CAPEX ~$100 MM per year, flexible as needed
- Ongoing plan of 3-5 wells annually

Production volumes, sales volumes, reserves and financial amounts exclude non-controlling interest, unless otherwise stated.
FOCUSING
On shareholder priorities

RAMPING
High value Eagle Ford Shale production

TRANSFORMING
Portfolio by adding oil-weighted, high-margin assets

PRODUCING
Oil-weighted assets that realize premium pricing

EXECUTING
Short cycle Gulf of Mexico field development projects

OFFERING
Investors exploration upside

POSITIONING
Company for Long-Term Value Creation

EXECUTING
Short cycle Gulf of Mexico field development projects
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.
### 4Q 2019 Guidance

<table>
<thead>
<tr>
<th>Producing Asset</th>
<th>Liquids (BOPD)</th>
<th>Gas (MCFD)</th>
<th>Total (BOEPD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>US – Eagle Ford Shale</td>
<td>48,300</td>
<td>31,300</td>
<td>53,500</td>
</tr>
<tr>
<td>Gulf of Mexico excluding NCI&lt;sup&gt;1&lt;/sup&gt;</td>
<td>72,700</td>
<td>73,600</td>
<td>85,000</td>
</tr>
<tr>
<td>Gulf of Mexico including NCI</td>
<td>84,800</td>
<td>78,700</td>
<td>98,000</td>
</tr>
<tr>
<td>Canada – Tupper Montney</td>
<td>–</td>
<td>264,000</td>
<td>44,000</td>
</tr>
<tr>
<td>Kaybob Duvernay and Placid Montney</td>
<td>6,700</td>
<td>22,500</td>
<td>10,500</td>
</tr>
<tr>
<td>Offshore</td>
<td>8,400</td>
<td>–</td>
<td>8,400</td>
</tr>
<tr>
<td>Other</td>
<td>600</td>
<td>–</td>
<td>600</td>
</tr>
</tbody>
</table>

| 4Q Production Volume (BOEPD) excluding NCI<sup>2</sup> | 198,000 – 206,000 |
| 4Q Production Volume (BOEPD) including NCI | 210,700 – 219,300 |
| 4Q Exploration Expense ($MM) | $21 |
| Full Year 2019 CAPEX ($BN) excluding NCI<sup>3</sup> | $1.35 – $1.45 |
| Full Year 2019 Production (BOEPD) excluding NCI<sup>4</sup> | 174,000 – 178,000 |

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<sup>1</sup> Excludes Noncontrolling Interest of MP GOM of 12,100 BOPD liquids and 5,100 MCFD gas
<sup>2</sup> Excludes Noncontrolling Interest of MP GOM of 13,000 BOEPD
<sup>3</sup> Excludes Noncontrolling Interest of MP GOM of $48 MM and $20 MM for assets held for sale
<sup>4</sup> Excludes Noncontrolling Interest of MP GOM of 12,600 BOEPD
2019 Hedging Positions

United States

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (BBL/D)</th>
<th>Price (BBL)</th>
<th>Start Date</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI</td>
<td>Fixed Price Derivative Swap</td>
<td>35,000</td>
<td>$60.51</td>
<td>10/1/2019</td>
<td>12/31/2019</td>
</tr>
<tr>
<td>WTI</td>
<td>Fixed Price Derivative Swap</td>
<td>45,000</td>
<td>$56.42</td>
<td>1/1/2020</td>
<td>12/31/2020</td>
</tr>
</tbody>
</table>

Montney, Canada

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Type</th>
<th>Volumes (MMCF/D)</th>
<th>Price (MCF)</th>
<th>Start Date</th>
<th>End Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales at AECO</td>
<td>59</td>
<td>C$2.81</td>
<td>10/1/2019</td>
<td>10/31/2019</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales at AECO</td>
<td>97</td>
<td>C$2.71</td>
<td>11/1/2019</td>
<td>3/31/2020</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>Fixed Price Forward Sales at AECO</td>
<td>59</td>
<td>C$2.81</td>
<td>4/1/2020</td>
<td>12/31/2020</td>
</tr>
</tbody>
</table>

* As of October 30, 2019
Current Financial Position
As of September 30, 2019

- $2.8 BN total debt, excluding capital leases
- Total liquidity $2.0 BN
- Approximately $435 MM of cash and cash equivalents
- Undrawn $1.6 BN unsecured senior credit facility
- 33% total debt to cap
- 28% net debt to cap

### Maturity Profile*

<table>
<thead>
<tr>
<th>Total Bonds Outstanding $BN</th>
<th>$2.8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Weighted Avg Fixed Coupon</td>
<td>5.5%</td>
</tr>
<tr>
<td>Weighted Avg Years to Maturity</td>
<td>7.0</td>
</tr>
</tbody>
</table>

* As of September 30, 2019

![Note Maturity Profile Chart]
Effective Governance Underpins Long-Term Financial Strength

Expert and Independent Board

- Long-term industry, operating, and HSE expertise
- Separate CEO and Chairman
- 12 out of 13 directors are independent
- Board of Directors elected with average vote of 99% over past 5 years

ESG Oversight

- Health, Safety and Environmental Committee established in 1993
  - Worldwide HSE policy and management system applied to every employee, contractor and partner
- Safety and environmental metrics in annual incentive plan performance since 2008
- Climate change oversight
  - Emissions forecasting in long-term planning
  - Developed guiding principles for climate change

ISS Governance Score vs peer average: 75%
Mitigating Risk Through Sustainable Environmental Operations

**Safe Operations**
- 0.32 average TRIR over past 4 years (vs 0.4 average for US E&P companies*)
- Eagle Ford Shale well work 5 years lost time accident free
- Vietnam seven years recordable free

**Spills Management**
- Zero International Oil and Gas Producers (IOGP) recordable spills 1H 2019
- Gulf of Mexico spill free since 2014
- Asset integrity focus across life-cycle, leading to significant reduction in spills

**GHG Emissions Reduction**
- 28% reduction from 2015 to 2018
- 50% reduction with 2018-2019 acquisition and divestment activity
- Long-term reductions with natural gas-fueled frac pumps in onshore Canada operations

*A Company reported data, sourced from Bloomberg

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**A proud member of The Environmental Partnership**

**Incident rate, spills rate, and emissions targets drive continual improvement**
Employee and Community Investments Support Stable Operations

Everywhere We Work

Competitive employee benefits
• Comprehensive health care coverage
• Retirement savings plans
• Education assistance program

Global Learning Management System
• ~300 professional development courses and more than 125 technical courses

North America

El Dorado Promise
• Tuition scholarship provided to El Dorado High School graduates
• College enrollment rate surpasses state and national levels

United Way
• Partners for more than 50 years
• Over $13 MM contributed in past 20 years

International

Process for new country entry
• Includes assessment of ESG risks

Social impact assessments
Community consultation processes
Prioritizing local suppliers
Threshold investment targets for local content
Adjusted Earnings

Murphy defines Adjusted Earnings as net income attributable to Murphy\(^1\) 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, except per share amounts</th>
<th>Three Months Ended – Sept 30, 2019</th>
<th>Three Months Ended – Sept 30, 2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income attributable to Murphy (GAAP)</td>
<td>1,089.0</td>
<td>93.9</td>
</tr>
<tr>
<td>Discontinued operations loss (income)</td>
<td>(953.4)</td>
<td>(37.8)</td>
</tr>
<tr>
<td>Income from continuing operations</td>
<td>135.6</td>
<td>56.1</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on crude oil derivative contracts</td>
<td>(38.9)</td>
<td>(20.6)</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on contingent consideration</td>
<td>(22.4)</td>
<td>–</td>
</tr>
<tr>
<td>Business development transaction costs</td>
<td>3.3</td>
<td>–</td>
</tr>
<tr>
<td>Tax benefits on investments in foreign areas</td>
<td>(15.0)</td>
<td>–</td>
</tr>
<tr>
<td>Write-off of previously suspended exploration wells</td>
<td>–</td>
<td>4.5</td>
</tr>
<tr>
<td>Foreign exchange losses (gains)</td>
<td>0.8</td>
<td>–</td>
</tr>
<tr>
<td>Ecuador arbitration settlement</td>
<td>–</td>
<td>(20.5)</td>
</tr>
<tr>
<td>Brunei working interest income</td>
<td>–</td>
<td>(16.0)</td>
</tr>
<tr>
<td>Seal insurance proceeds</td>
<td>(6.2)</td>
<td>(7.0)</td>
</tr>
<tr>
<td>Adjusted Income (loss) attributable to Murphy (Non-GAAP)</td>
<td>57.2</td>
<td>(3.5)</td>
</tr>
<tr>
<td>Adjusted income (loss) from continuing operations per diluted share</td>
<td>0.36</td>
<td>(0.02)</td>
</tr>
</tbody>
</table>

1 ‘Attributable to Murphy’ represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
Non-GAAP Reconciliation

**EBITDA and EBITDAX**

Murphy defines EBITDA as income from continuing operations attributable to Murphy before interest, taxes, depreciation and amortization (DD&A). Murphy defines EBITDAX as income from continuing operations attributable to Murphy 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 exclude 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>$ Millions</th>
<th>Three Months Ended – Sept 30, 2019</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Net income (loss) attributable to Murphy (GAAP)</td>
<td>1,089.0</td>
<td>93.9</td>
</tr>
<tr>
<td>Income tax expense (benefit)</td>
<td>18.8</td>
<td>17.8</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>44.9</td>
<td>44.2</td>
</tr>
<tr>
<td>DD&amp;A expense</td>
<td>308.3</td>
<td>197.5</td>
</tr>
<tr>
<td>EBITDA attributable to Murphy (Non-GAAP)</td>
<td>1,461.0</td>
<td>353.4</td>
</tr>
<tr>
<td>Exploration expense</td>
<td>12.4</td>
<td>21.7</td>
</tr>
<tr>
<td>EBITDAX attributable to Murphy (Non-GAAP)</td>
<td>1,473.4</td>
<td>375.1</td>
</tr>
<tr>
<td>Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)</td>
<td>17,745</td>
<td>11,232</td>
</tr>
<tr>
<td>EBITDAX per BOE (Non-GAAP)</td>
<td>83.03</td>
<td>33.39</td>
</tr>
</tbody>
</table>

1 'Attributable to Murphy' represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
**ADJUSTED EBITDA**

Murphy defines Adjusted EBITDA as income from continuing operations attributable to Murphy¹ before interest, taxes, depreciation and amortization (DD&A), 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 EBITDA is used by management to evaluate the company’s operational performance and trends between periods and relative to its industry competitors. Adjusted EBITDA may not be comparable to similarly titled measures used by other companies and it should be considered in conjunction with generally accepted accounting principles (GAAP). Adjusted EBITDA has certain limitations regarding financial assessments because it excludes certain items that affect net income and net cash provided by operating activities. Adjusted EBITDA 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, except per BOE amounts</th>
<th>Three Months Ended – Sept 30, 2019</th>
<th>Three Months Ended – Sept 30, 2018</th>
</tr>
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<tr>
<td>EBITDA attributable to Murphy (Non-GAAP)</td>
<td>1,461.0</td>
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<td>(37.8)</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on crude oil derivative contracts</td>
<td>(49.2)</td>
<td>(26.0)</td>
</tr>
<tr>
<td>Accretion of asset retirement obligations</td>
<td>10.6</td>
<td>6.5</td>
</tr>
<tr>
<td>Business development transaction costs</td>
<td>4.1</td>
<td>-</td>
</tr>
<tr>
<td>Write-off of previously suspended exploration wells</td>
<td>-</td>
<td>4.5</td>
</tr>
<tr>
<td>Seal insurance proceeds</td>
<td>(8.0)</td>
<td>(9.7)</td>
</tr>
<tr>
<td>Foreign exchange losses (gains)</td>
<td>0.8</td>
<td>(1.0)</td>
</tr>
<tr>
<td>Mark-to-market (gain) loss on contingent consideration</td>
<td>(28.4)</td>
<td>-</td>
</tr>
<tr>
<td>Ecuador arbitration settlement</td>
<td>-</td>
<td>(26.0)</td>
</tr>
<tr>
<td>Brunei working interest income</td>
<td>-</td>
<td>(16.0)</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA attributable to Murphy (Non-GAAP)</strong></td>
<td><strong>437.5</strong></td>
<td><strong>247.9</strong></td>
</tr>
<tr>
<td>Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)</td>
<td>17,745</td>
<td>11,232</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA per BOE (Non-GAAP)</strong></td>
<td><strong>24.65</strong></td>
<td><strong>22.07</strong></td>
</tr>
</tbody>
</table>

¹ ‘Attributable to Murphy’ represents the economic interest of Murphy excluding a 20% noncontrolling interest in MP GOM.
Glossary of Abbreviations

BBL: Barrels (equal to 42 US gallons)

BCF: Billion cubic feet

BCFE: Billion cubic feet equivalent

BN: Billions

BOE: Barrels of oil equivalent (1 barrel of oil or 6,000 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

G&A: General and administrative expenses

GOM: Gulf of Mexico

LOE: Lease operating expense

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

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)
Positioned for Investor Value Creation

4.3% Dividend Yield
Longstanding & Competitive

28% Net Debt to Cap
At September 30, 2019

1.3x Net Debt / EBITDAX*
At September 30, 2019

* 3Q 2019 annualized adjusted EBITDAX
Eagle Ford Shale
Peer Acreage
Eagle Ford Shale
Murphy Spacing vs Peers

Catarina Typical Murphy Spacing
LEFS ~300’ to 600’

SE Offset Spacing
LEFS ~ 250’ to 300’

EOG Offset Spacing
LEFS ~250’ to 500’

Karnes Typical Murphy Spacing
LEFS ~250-500’

DVN Offset Spacing
LEFS ~250’ to 500’

COP Offset Spacing
LEFS ~250’ to 600’

Tilden Typical Murphy Spacing
LEFS ~350’ to 800’

MRO Offset Spacing
LEFS ~250’ to 600’

CHK Offset Spacing
LEFS ~350’ to 1000’

EOG Offset Spacing
LEFS ~250’ to 500’

MRO Offset Spacing
LEFS ~250’ to 600’

COP Offset Spacing
LEFS ~250’ to 600’

DVN Offset Spacing
LEFS ~250’ to 500’

BP
Chesapeake
Conoco
Devon
Encana
EOG
Equinor (Statoil)
Inpex (Gulftex)
Magnolia
Marathon
Pioneer
Sanchez