



INVESTOR UPDATE

MAY 2021

ROGER W. JENKINS

PRESIDENT & CHIEF EXECUTIVE OFFICER

Cautionary Statement and Investor Relations Contacts

Cautionary Note to US 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: macro conditions in the oil and natural gas industry, including supply/demand levels, actions taken by major oil exporters and the resulting impacts on commodity prices; 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; the impact on our operations or market of health pandemics such as COVID-19 and related government responses; other natural hazards impacting our operations or markets; 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; or adverse developments in the US 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 US 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. Definitions of these measures are included in the appendix.

Kelly Whitley

VP, Investor Relations & Communications
281-675-9107

kelly_whitley@murphyoilcorp.com

Megan Larson

Staff Investor Relations Analyst
281-675-9470

megan_larson@murphyoilcorp.com

Why Murphy Oil?



Oil and natural gas assets that are safely operated with low carbon emissions intensity in three operating areas across North America



High-potential exploration portfolio with industry-leading offshore capabilities



Strong generator of free cash flow with capital allocation flexibility



Financial discipline has led to 60-year track record of returning capital to shareholders



Supported by multi-decade founding family, with meaningful board and management ownership



Our 2021 Priorities

DELEVER

- Achieved debt reduction of 8%, or ~\$230 MM, in 1Q 2021
- Goal of further ~\$200 MM in 2021, for total of ~15% reduction FY 2021 at current strip prices

EXECUTE

- Brought onshore wells online ahead of schedule and under budget
- Produced 88 MBOPD oil, or 7% above guide, with Eagle Ford Shale 4% above despite winter storm impact
- Remain on schedule for major offshore projects

EXPLORE

- Spud Silverback exploration well in Gulf of Mexico in 2Q 2021
- Cutthroat exploration well in Brazil planned to spud in 3Q 2021

Capital Execution and Guidance

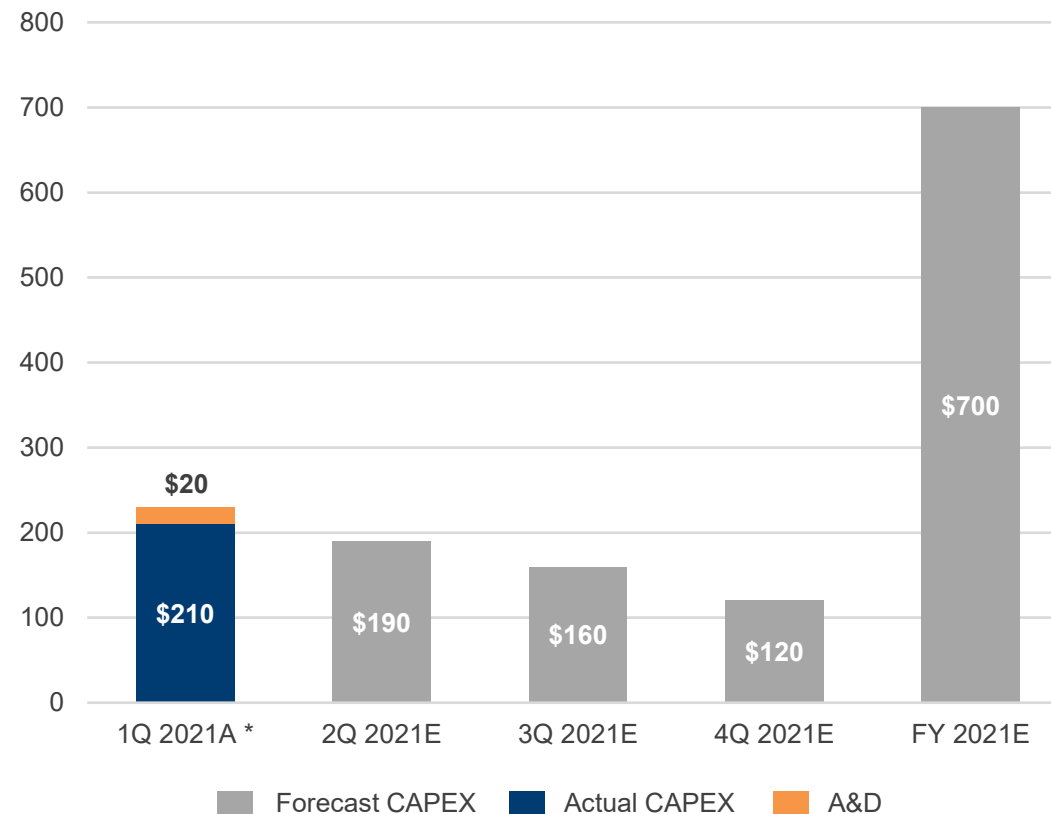
Executing In-Line With Plan

- 1Q 2021 accrued CAPEX* of \$230 MM aligned with plan
 - Includes \$20 MM cost of Lucius WI acquisition
- Primary business units' CAPEX heavily weighted to 1Q 2021
 - Eagle Ford Shale 44% of FY 2021 plan
 - Gulf of Mexico 38% of FY 2021 plan
 - Onshore Canada 35% of FY 2021 plan

Outperformance Leads to Production Guidance Raise

- Improved drilling technical performance while reducing costs
- Guiding 2Q 2021 production of 160 – 168 MBOEPD, with midpoint of oil production at 95 MBOPD
- Tightening FY 2021 production guidance to 157 – 165 MBOEPD
 - Accounts for additional 1 MBOEPD of acquired Lucius production
 - Maintain FY 2021 CAPEX guide of \$675 – \$725 MM

Accrued CAPEX by Quarter \$MM



Accrual CAPEX, based on midpoint of guidance range and excluding noncontrolling interest

* Excludes King's Quay CAPEX of \$17 MM

Balance Sheet Stability

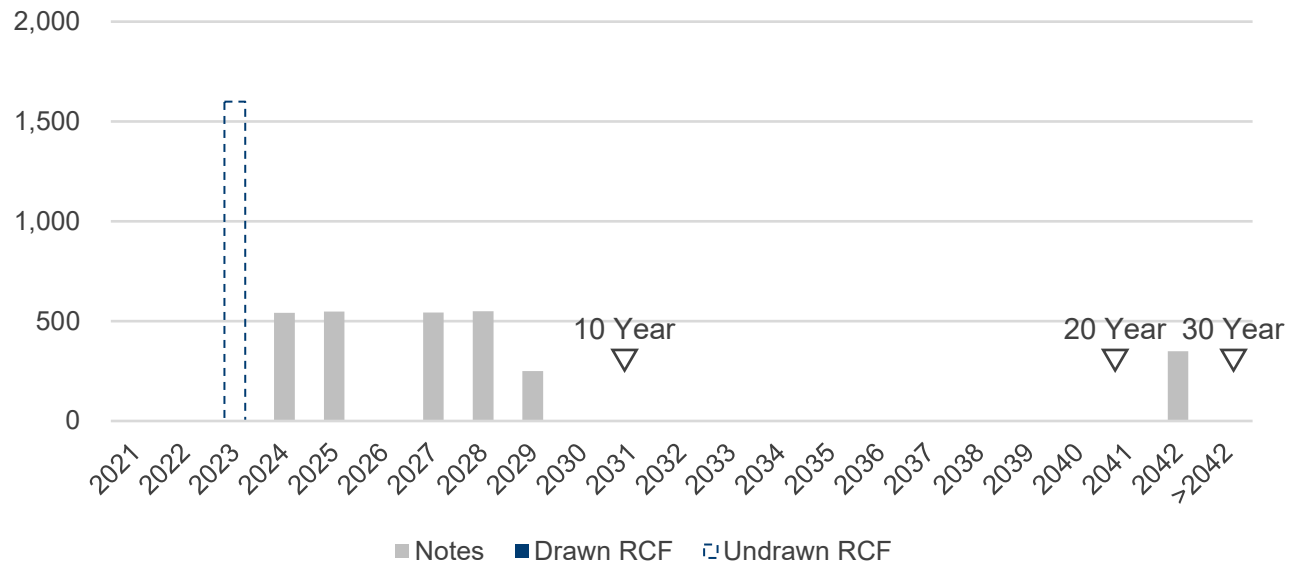
Solid Foundation for Commodity Price Cycles

- \$1.6 BN senior unsecured credit facility matures Nov 2023, undrawn at March 31, 2021
- All debt is unsecured, senior credit facility not subject to semi-annual borrowing base redeterminations
- \$231 MM of cash and cash equivalents at March 31, 2021
- Next senior notes maturity due in 2024
- 41% total debt to cap, 39% net debt to cap

Maturity Profile*

Total Bonds Outstanding \$BN	\$2.756
Weighted Avg Fixed Coupon	6.3%
Weighted Avg Years to Maturity	7.7

Note Maturity Profile \$MM



* As of March 31, 2021

Focusing on ESG Priorities

Reducing Impact Through Operational Focus

- Lowering carbon emissions intensity 15 – 20% by 2030*, tied to compensation goal
- Reduce flaring by developing alternate export infrastructure
- Improving efficiency through compressor upgrades and engineering controls

Realized Cost Savings

- Displaced ~1 MM gal of diesel with clean-burning natural gas in D&C operations
 - ~\$1.3 MM cost savings across North America onshore
- Utilized 800 MBBLS of recycled water in completions
 - ~\$3 MM in disposal cost savings
- Electrification of third-party processing plant in Tupper Montney, resulting in lower emissions

* From 2019, excluding Malaysia



Proud member of

THE
ENVIRONMENTAL
PARTNERSHIP

 **GOVERNANCE**
QUALITYSCORE
HIGHEST RANKED BY **ISS ESG** 

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ONSHORE PORTFOLIO UPDATE



North America Onshore

Balancing Investments for Free Cash Generation to Delever Balance Sheet

1Q 2021 Onshore Activity

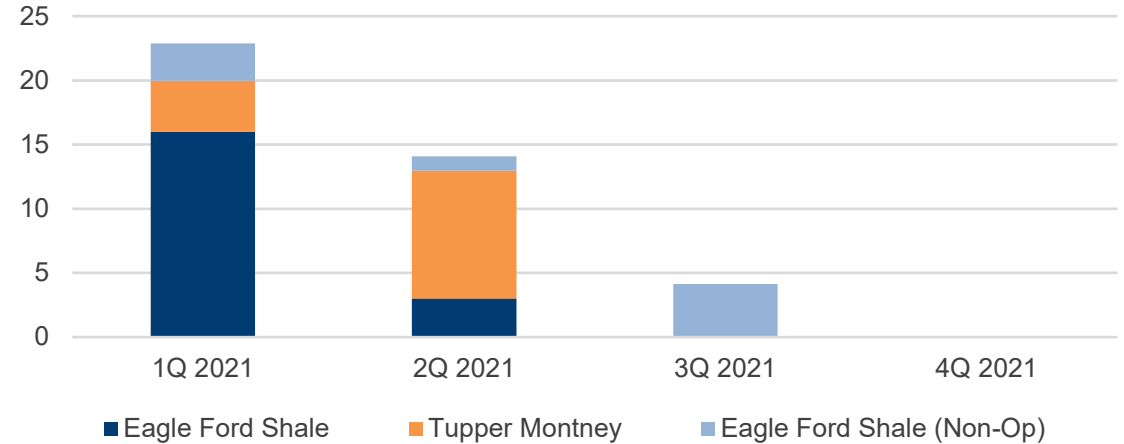
- Eagle Ford Shale
 - 16 operated wells + 16 gross non-operated wells* online
 - \$75 MM of \$170 MM FY 2021 CAPEX guidance
- Tupper Montney
 - 4 operated wells online
 - \$30 MM of \$85 MM FY 2021 CAPEX guidance

FY 2021 Onshore Activity

- Eagle Ford Shale
 - 19 operated + 45 gross non-operated wells* online
- Tupper Montney
 - 14 operated wells online

* Eagle Ford Shale non-operated wells average 18% working interest

2021 Wells Online



Note: Non-op well cadence subject to change per operator plans
Eagle Ford Shale non-operated wells adjusted for 18% average working interest

Eagle Ford Shale

Base Production Outperforms While Lowering Costs

1Q 2021 Activity

- 16 operated wells online, all Karnes
 - Primarily Lower EFS and Austin Chalk
 - Avg 1,400 BOEPD IP30
 - Two best wells achieved 2,000 BOEPD IP30

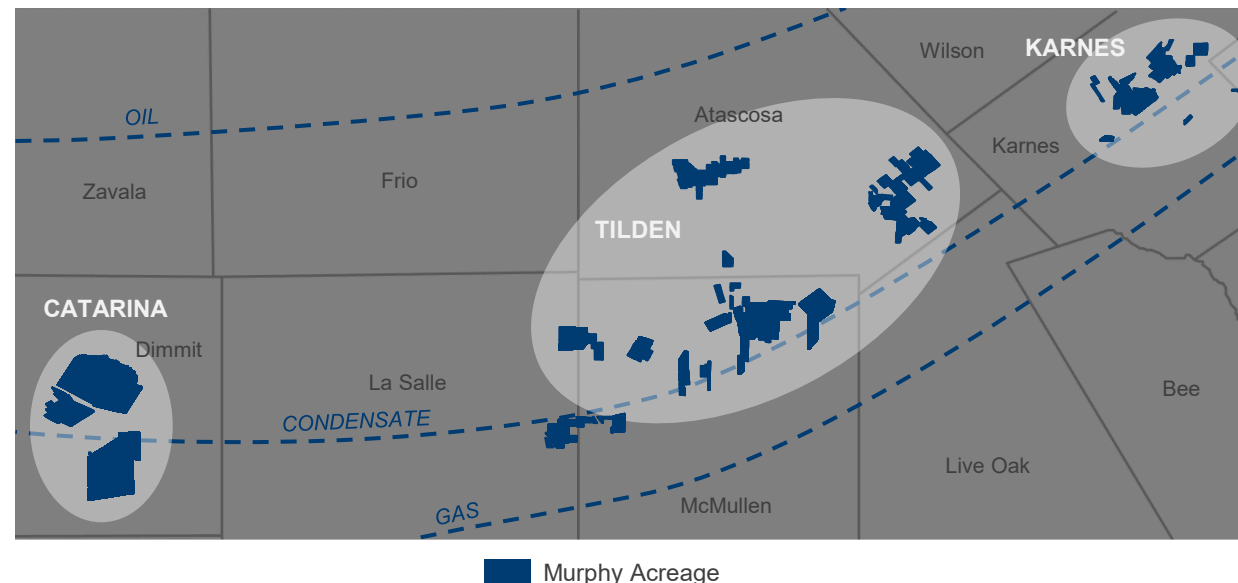
Lowering D&C Costs

- 40% reduction in completions costs since FY 2018
- ~\$4.5 MM avg well cost in 1Q 2021, down from ~\$6.3 MM in FY 2018
- Karnes avg cost per well in-line with top peers

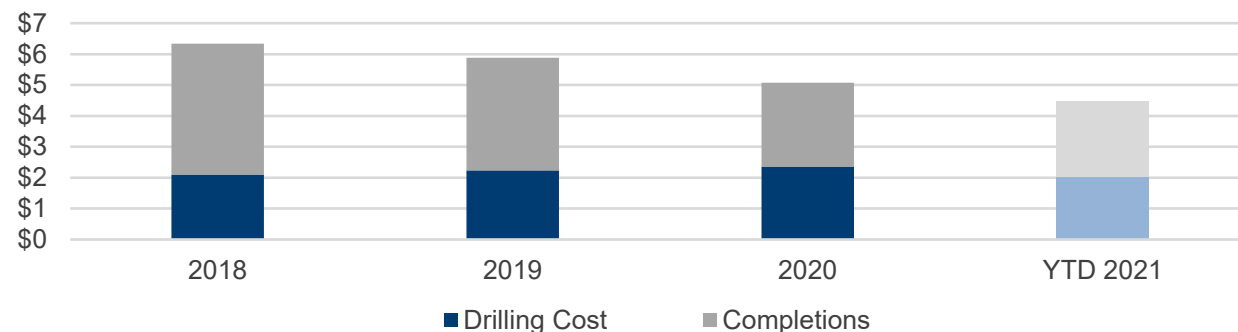
Achieving Strong Austin Chalk Results

- 1Q 2021 Karnes Tier 2 wells meaningfully outperforming Tier 1 type curve
 - Avg 1,400 BOEPD IP30 rate
- Reassessing ultimate recovery expectations based on results
 - ~100 Karnes locations as of YE 2020

Eagle Ford Shale Acreage



Eagle Ford Shale Drilling and Completions \$MM per well



Tupper Montney

Increasing Recoveries While Lowering Costs

1Q 2021 Activity

- 4 wells online, 45 days ahead of plan

Lowering D&C costs

- 28% reduction since FY 2017
- ~\$4.1 MM avg well cost in 1Q 2021, down from ~\$5.5 MM in FY 2019

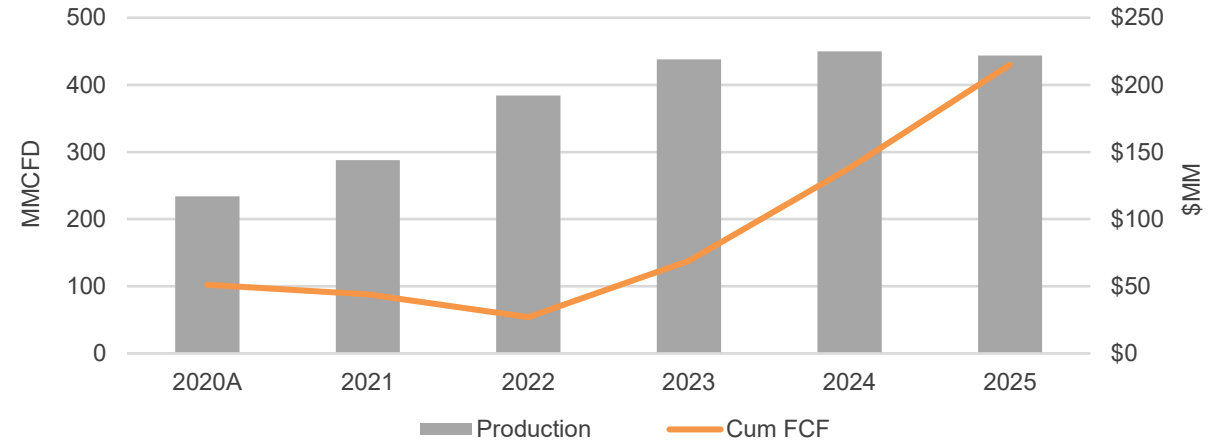
~1,400 Remaining Locations* Support a Low-Carbon Energy Future

Low Execution Risk

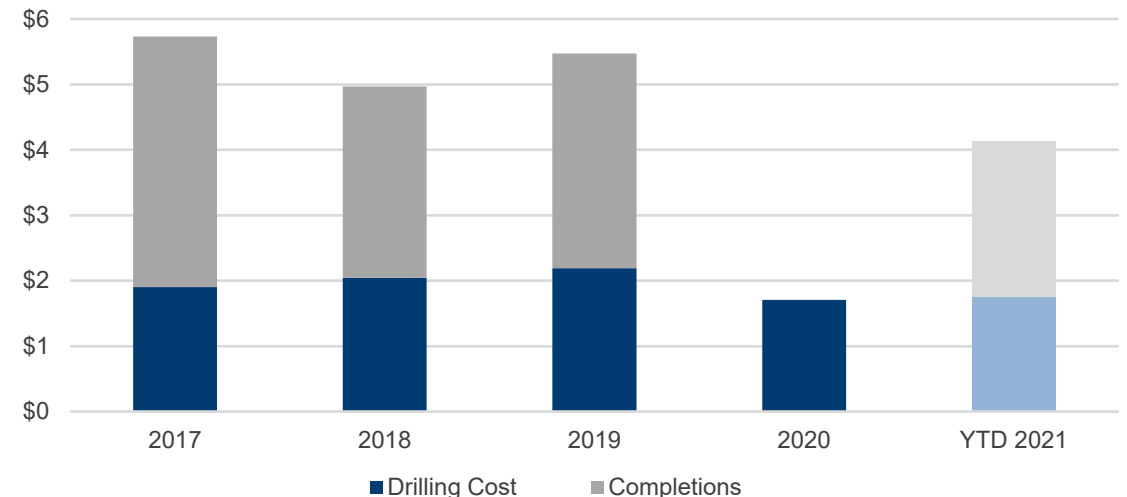
- Average ultimate recovery of ~21 BCF / well
- Low subsurface risk from proven resource
- Ample existing take-away and infrastructure in place

* Includes contingent well count

Tupper Montney Production and Cumulative FCF



Tupper Montney Drilling and Completions \$MM per well



Kaybob Duvernay

FY 2021

- No activity planned
- \$9 MM CAPEX for field development

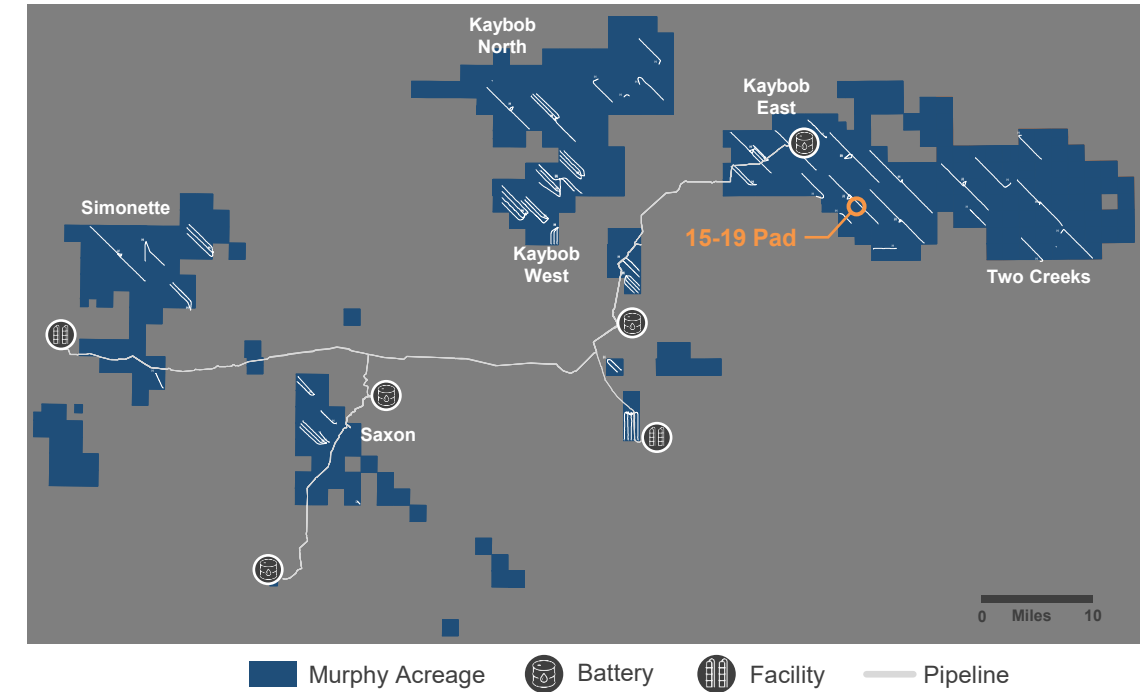
Lower Costs Support Long-Term Development

- Established integrated remote operating center, reduces downtime and costs
- Industry-leading well productivity, in-line with core performance of other top NA shale plays
- Tightening differentials leading to improved cash flow

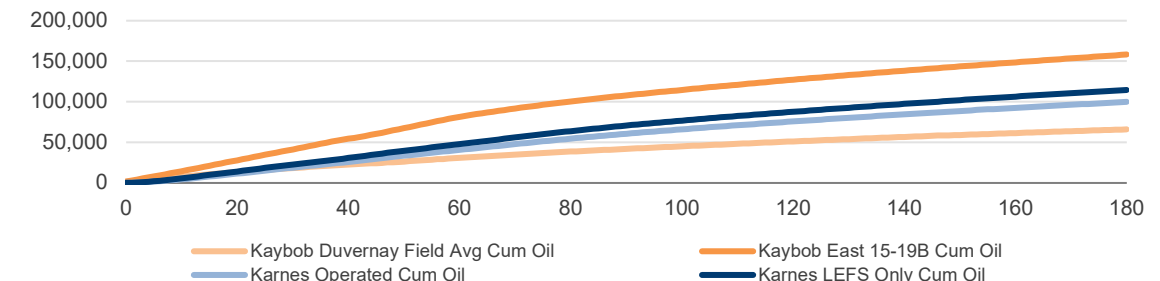
Kaybob East 15-19 Pad

- Online 3Q 2020
- Competitive with top producing EFS Karnes wells
- 180-day cumulative oil production
 - Best well performer in Kaybob Duvernay
 - Top 2% of Murphy unconventional wells

Kaybob Duvernay Acreage



Cumulative Oil *BOPD*



OFFSHORE PORTFOLIO UPDATE



Gulf of Mexico

Major Projects Drive Future Free Cash Flow

Khaleesi / Mormont / Samurai

- Launched drilling campaign 2Q 2021
 - Drilled top hole sections for 3 wells
 - Currently drilling Samurai #3 well
- On track for first oil in 1H 2022

St. Malo Waterflood

- First producer well online
- Drilling final well of 4-well campaign in 2Q 2021

Facilities

Project Components	Fabrication	Commissioning	Installation / Hook-up
King's Quay FPS	✓	3Q 2021 – 2Q 2022	1H 2022
King's Quay Moorings	✓	N/A	2Q 2021 / 4Q 2021
Subsea Flowlines and Equipment	Ongoing	1H 2022	4Q 2021 – 3Q 2022

Drilling and Completions

Field	Drilled	Completions	Online
Khaleesi	✓ ✓ ●	4Q 2021	1H 2022
Mormont	✓ ✓	1Q 2022	1H 2022
Samurai	✓ ●	2Q 2022	2H 2022



Planned well



Drilling in progress



Drilled well

See Appendix for major project CAPEX and production cadence

King's Quay Floating Production System

King's Quay Floating Production System

- Monetization closed 1Q 2021 for \$268 MM of proceeds
- Completed construction in 2Q 2021
- Sail away to Gulf of Mexico on track for 3Q 2021
- On track to receive first oil 1H 2022

King's Quay – Platform Crane Installation



EXPLORATION UPDATE



Exploration Strategy Overview

Focused and Meaningful

- Four primary exploration areas
- Target up to 5 total exploration wells per year
- Flexible capital spending to preserve large resources
- Portfolio upside maintains long-term resilience

Reduced Risk

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

Strategic Themes

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

Exploration Core Focus Areas



2021 Exploration Plan

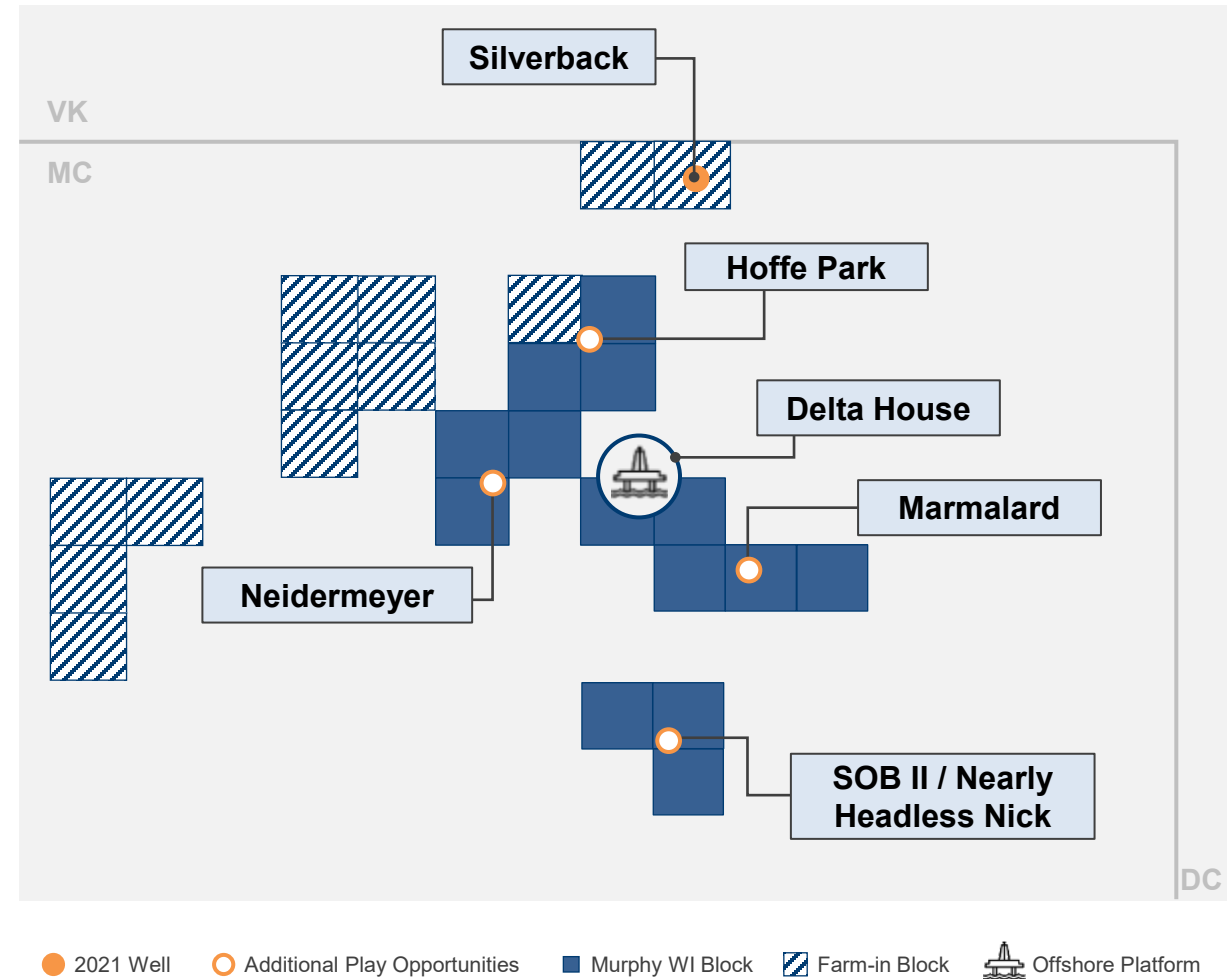
Gulf of Mexico – Mississippi Canyon 35

Asset Overview

- Chevron 80% (Op), Murphy 10%, Ecopetrol 10%
- Acreage is adjacent to large position held by Murphy and partners
 - Additional play opportunities
- Farm-in results in access to 12 blocks via Silverback well participation

Silverback #1 (Mississippi Canyon 35)

- Targeting attractive, play-opening trend
- Spud 2Q 2021



2021 Exploration Plan

Sergipe-Alagoas Basin, Brazil

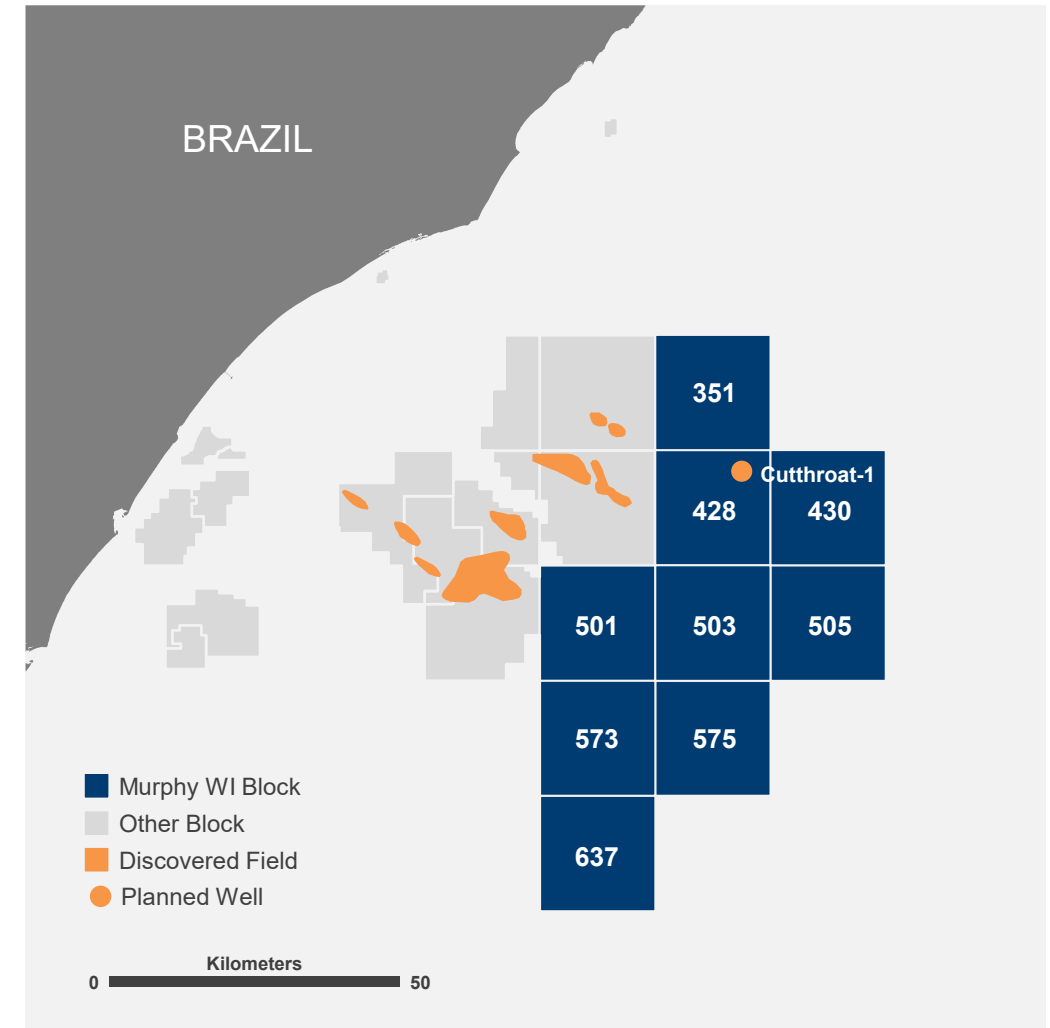
Asset Overview

- ExxonMobil 50% (Op), Enauta Energia S.A. 30%, Murphy 20%
- Hold WI in 9 blocks, spanning >1.6 MM acres
- >2.8 BN BOE discovered in basin
- >1.2 BN BOE in deepwater since 2007
- Material opportunities identified on Murphy WI blocks

Drilling Program

- On track for drilling Cutthroat-1 in 2H 2021
 - ~\$15 MM net cost
- Mean to upward gross resource potential
 - 500 MMBOE – 1,050 MMBOE
- Continuing to mature inventory and plan future well timing

Sergipe-Alagoas Basin



All blocks begin with SEAL-M

LOOKING AHEAD



2021 Capital Program



**2021
GUIDANCE**

Production
2Q 2021 **160 - 168 MBOEPD**

Production
FY 2021 **157 - 165 MBOEPD**

CAPEX
FY 2021 **\$675 - \$725 Million**

Focusing CAPEX on High-Margin Assets

- \$325 MM allocated to Gulf of Mexico
 - 2021 Gulf of Mexico spending primarily directed toward major projects, providing long-term production volumes
- \$170 MM allocated to Eagle Ford Shale
- \$85 MM allocated to Tupper Montney

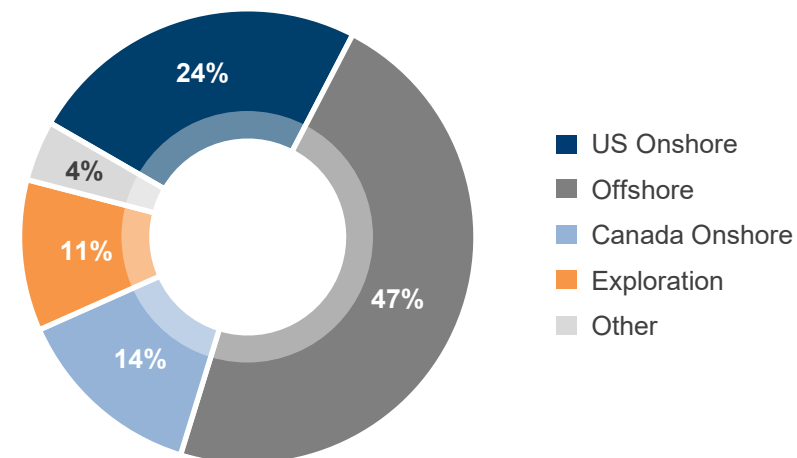
Producing from our Oil-Weighted Portfolio

- 54% oil-weighted production in 2021, 60% liquids-weighted production in 2021

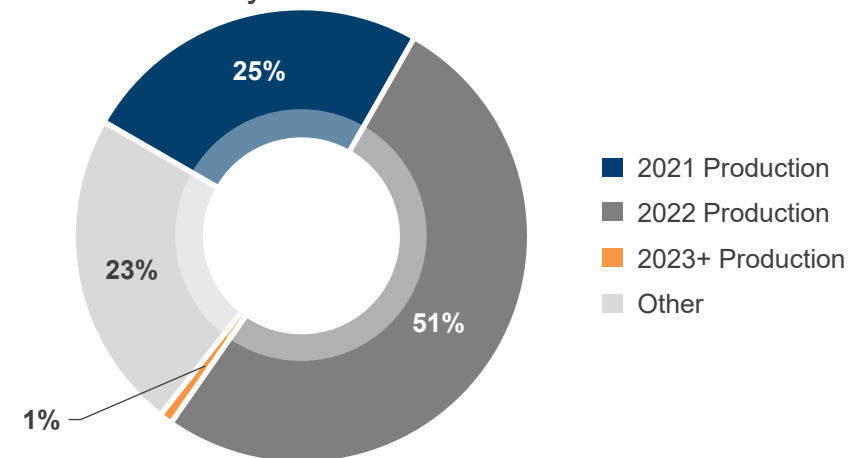
Managing Risk With Commodity Hedges to Underpin Capital Returns

Note: Production volumes, sales volumes, reserves and financial amounts exclude noncontrolling interest, unless otherwise stated

2021 Total CAPEX



CAPEX by Production Year



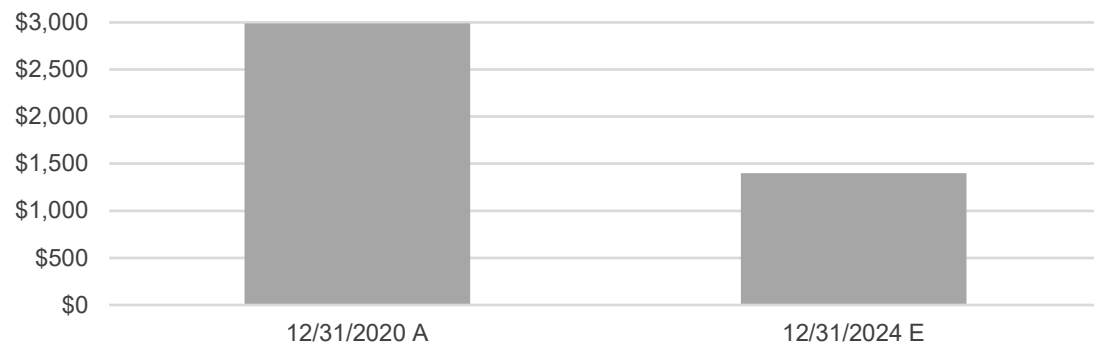
Note: 2022 production includes St. Malo waterflood, Khaleesi, Mormont and Samurai projects. 2023+ production includes exploration

Disciplined Strategy Leads to Long-Term Value

Delever, Execute, Explore 2021 – 2024

- Achieve < \$1.4 BN debt by 2024*
- Spend annual average CAPEX of ~\$600 MM
- Deliver production CAGR of ~6% in 2021 – 2024
- Produce consistent oil-weighting, ~50% in 2021 – 2024
- Maintain offshore production average of ~75 MBOEPD in 2021 – 2024
- Advance exploration portfolio of > 1 BBOE net risked potential resources
- Pay consistent dividend to shareholders

Forecast Debt Outstanding \$MMs

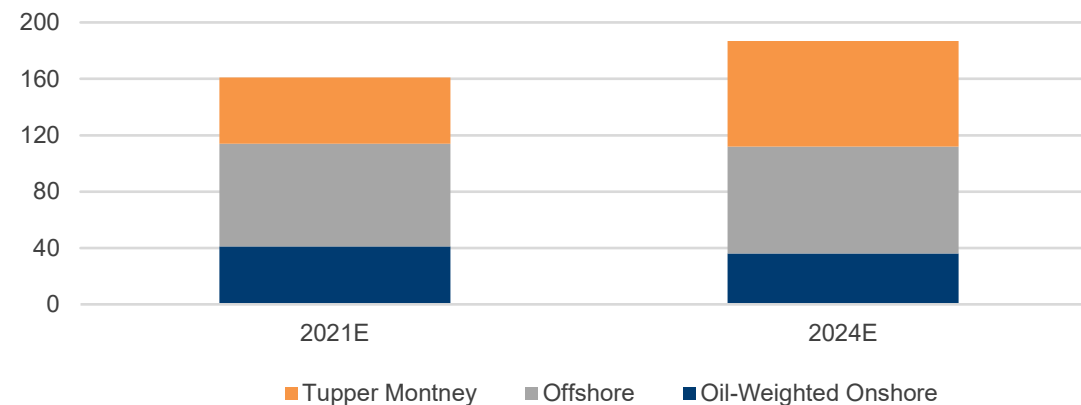


* Assumes long-term \$60 WTI oil price

Capital Allocation Optionality

- Reduce debt further
- Allocate additional capital to assets
- Fund exploration success
- Evaluate strategic A&D opportunities
- Return additional cash to shareholders

2021E – 2024E Production MBOEPD



Note: Oil-weighted onshore includes Eagle Ford Shale and Kaybob Duvernay

Focused on Targeted Priorities

DELEVER

- Goal of further ~\$200 MM, for total of ~15% reduction in FY 2021 at current strip prices
- Plan allows for debt reduction to ~\$1.4 BN by FYE 2024 from FYE 2020, with potential for further reductions long-term

EXECUTE

- Progress major projects in the Gulf of Mexico ahead of first oil in 1H 2022
- Continue achieving drilling and completions cost efficiencies and lowering emissions intensity
- Maintain strong safety and environmental metrics

EXPLORE

- Focus on drilling 2 non-op wells in Gulf of Mexico and Brazil in 2021
- Progress on 2022 exploration plans with partners

Why Murphy Oil?



Oil and natural gas assets that are safely operated with low carbon emissions intensity in three operating areas across North America



High-potential exploration portfolio with industry-leading offshore capabilities



Strong generator of free cash flow with capital allocation flexibility



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Appendix



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Non-GAAP Definitions and Reconciliations

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Glossary of Abbreviations

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2Q 2021 Guidance

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Current Hedging Positions

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Acreage Maps

Non-GAAP Financial Measure Definitions and 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

EBITDA and EBITDAX

Murphy defines EBITDA as net income (loss) attributable to Murphy¹ before interest, taxes, depreciation and amortization (DD&A). Murphy defines EBITDAX as net income (loss) attributable to Murphy before interest, taxes, depreciation and amortization (DD&A) and exploration expense.

Management believes that EBITDA and EBITDAX provide useful information for assessing Murphy's financial condition and results of operations and are widely accepted financial indicators of the ability of a company to incur and service debt, fund capital expenditure programs, 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 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.

<i>\$ Millions</i>	Three Months Ended – Mar 31, 2021	Three Months Ended – Mar 31, 2020
Net (loss) income attributable to Murphy (GAAP)	(287.4)	(416.1)
Income tax (benefit) expense	(88.2)	(91.5)
Interest expense, net	88.1	41.1
DD&A expense	188.3	286.2
EBITDA attributable to Murphy (Non-GAAP)	(99.2)	(180.3)
Exploration expense	11.8	20.1
EBITDAX attributable to Murphy (Non-GAAP)	(87.4)	(160.2)

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

Non-GAAP Reconciliation

ADJUSTED EBITDA

Murphy defines Adjusted EBITDA as net income (loss) attributable to Murphy¹ before interest, taxes, depreciation and amortization (DD&A), impairment expense, discontinued operations, foreign exchange gains and losses, mark-to-market gains and losses 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.

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<i>\$ Millions, except per BOE amounts</i>	Three Months Ended – Mar 31, 2021	Three Months Ended – Mar 31, 2020
EBITDA attributable to Murphy (Non-GAAP)	(99.2)	(180.3)
Impairment of assets	171.3	866.4
Mark-to-market loss (gain) on crude oil derivative contracts	153.5	(358.3)
Mark-to-market loss (gain) on contingent consideration	14.9	(59.2)
Accretion of asset retirement obligations	10.5	10.0
Unutilized rig charges	2.8	3.5
Foreign exchange losses (gains)	1.3	(4.7)
Discontinued operations (income) loss	(0.2)	4.9
Inventory loss	-	4.8
Adjusted EBITDA attributable to Murphy (Non-GAAP)	254.9	287.1
Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)	13,670	17,071
Adjusted EBITDA per BOE (Non-GAAP)	18.65	16.82

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

Non-GAAP Reconciliation

ADJUSTED EBITDAX

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Mark-to-market loss (gain) on contingent consideration	14.9	(59.2)
Accretion of asset retirement obligations	10.5	10.0
Unutilized rig charges	2.8	3.5
Foreign exchange losses (gains)	1.3	(4.7)
Discontinued operations (income) loss	(0.2)	4.9
Inventory loss	-	4.8
Adjusted EBITDAX attributable to Murphy (Non-GAAP)	266.7	307.2
Total barrels of oil equivalents sold from continuing operations attributable to Murphy (thousands of barrels)	13,670	17,071
Adjusted EBITDAX per BOE (Non-GAAP)	19.51	17.99

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)

2Q 2021 Guidance

Producing Asset	Oil (BOPD)	NGLs (BOPD)	Gas (MCFD)	Total (BOEPD)
US – Eagle Ford Shale	28,300	5,000	27,400	37,900
– Gulf of Mexico excluding NCI ¹	57,400	5,100	68,800	74,000
Canada – Tupper Montney	–	–	236,400	39,400
– Kaybob Duvernay and Placid Montney	5,400	1,000	18,200	9,400
– Offshore	3,300	–	–	3,300

2Q Production Volume (BOEPD) <i>excl. NCI</i> ¹	160,000 – 168,000
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2Q Exploration Expense (\$MM)	\$20
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Full Year 2021 CAPEX (\$MM) <i>excl. NCI</i> ²	\$675 – \$725
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Full Year 2021 Production Volume (BOEPD) <i>excl. NCI</i> ³	157,000 – 165,000
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¹ Excludes noncontrolling interest of MP GOM of 9,500 BOPD oil, 600 BOPD NGLs and 4,600 MCFD gas

² Excludes noncontrolling interest of MP GOM of \$30 MM

³ Excludes noncontrolling interest of MP GOM of 8,800 BOPD oil, 500 BOPD NGLs and 4,300 MCFD gas

Current Hedging Positions

United States

Commodity	Type	Volumes (BBL/D)	Price (BBL)	Start Date	End Date
WTI	Fixed Price Derivative Swap	45,000	\$42.77	4/1/2021	12/31/2021
WTI	Fixed Price Derivative Swap	20,000	\$44.88	1/1/2022	12/31/2022

Montney, Canada

Commodity	Type	Volumes (MMCF/D)	Price (MCF)	Start Date	End Date
Natural Gas	Fixed Price Forward Sales at AECO	203	C\$2.55	4/1/2021	5/31/2021
Natural Gas	Fixed Price Forward Sales at AECO	241	C\$2.57	6/1/2021	12/31/2021
Natural Gas	Fixed Price Forward Sales at AECO	231	C\$2.42	1/1/2022	1/31/2022
Natural Gas	Fixed Price Forward Sales at AECO	221	C\$2.41	2/1/2022	4/30/2022
Natural Gas	Fixed Price Forward Sales at AECO	250	C\$2.40	5/1/2022	5/31/2022
Natural Gas	Fixed Price Forward Sales at AECO	292	C\$2.39	6/1/2022	12/31/2022
Natural Gas	Fixed Price Forward Sales at AECO	201	C\$2.36	1/1/2023	12/31/2023
Natural Gas	Fixed Price Forward Sales at AECO	147	C\$2.41	1/1/2024	12/31/2024

* As of May 5, 2020

1Q 2021 Cash Flow Simplification

Cash Flow Adjustments

- Total inflow of cash of \$1,048 MM
 - From operations, King's Quay monetization and senior notes transactions
- Total outflow of \$1,128 MM
 - From transactions, dividends and distribution to NCI
 - Includes \$20 MM cost of Lucius WI acquisition and \$233 MM of net debt reduction
- Resulted in \$80 MM cash deficit for the quarter, funded with cash on hand
 - \$231 MM cash and equivalents as of March 31, 2021
- At current prices, goal of repurchasing additional ~\$200 MM of senior notes in 2021

Cash Flow Attributable to Murphy (\$MM)	Inflow	Outflow	Net
Cash from operations and property additions ¹	\$238	(\$241)	(\$3)
King's Quay monetization	\$268	(\$218) ²	\$50
Senior notes transactions	\$542	(\$610) ³	(\$68)
Dividends		(\$19)	(\$19)
Distribution to noncontrolling interest		(\$36)	(\$36)
Other		(\$4)	(\$4)
Net Cash Flow	\$1,048	(\$1,128)	(\$80)

¹ Includes noncontrolling interest

² Includes 1Q 2021 CAPEX of \$18 MM plus revolver payoff of \$200 MM

³ Includes 2022 notes principal amount of \$576 MM plus \$34 MM early redemption of debt cost



Eagle Ford Shale Operated Well Locations

Area	Net Acres	Reservoir	Inter-Well Spacing (ft)	Remaining Wells
Karnes	10,092	Lower EFS	300	106
		Upper EFS	600	142
		Austin Chalk	1,200	97
Tilden	64,770	Lower EFS	600	264
		Upper EFS	500	138
		Austin Chalk	600	100
Catarina	48,375	Lower EFS	550	238
		Upper EFS	950	219
		Austin Chalk	1,200	112
Total	123,237			1,416

**As of December 31, 2020*

Kaybob Duvernay Well Locations

Area	Net Acres	Inter-Well Spacing (ft)	Remaining Wells
Two Creeks	35,232	984	104
Kaybob East	37,744	984	152
Kaybob West	25,984	984	107
Kaybob North	25,536	984	98
Simonette	32,116	984	108
Saxon	12,298	984	57
Total	168,910		626

**As of December 31, 2020*

Tupper Montney Project

Low Carbon Intensity Development With Attractive Cash Margins

Tupper Montney Advantages

- Employ capital allocation process that maximizes free long term cash flow
 - Generates greater cash margin per well than Eagle Ford Shale at conservative prices
 - < \$1 / MCF average new well breakeven cost
- Long history of continuous improvement
 - Increasing laterals to ~11,000'
 - Improved drilling and completion costs to ~\$5 MM / well
 - Increased average ultimate recovery to ~21 BCF / well

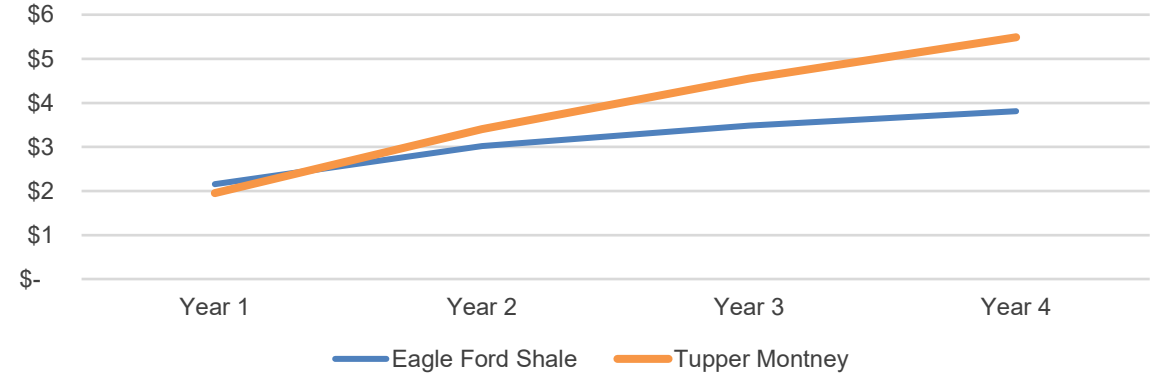
Improved Macro Economics for Region

- Increased local take-away capacity and debottlenecking completed
 - 600 MMCFD westward export 2020 – 2022
 - 1.3 BCFD eastward export 2021 – 2022
- Declining regional production 2 BCFPD lower Y-o-Y
- Improved domestic demand due to coal to natural gas switching
- Construction underway for LNG Canada project, estimated in service in 2025
- Lowest AECO to Henry Hub basis differential in 5 years

Low Carbon Intensity Asset

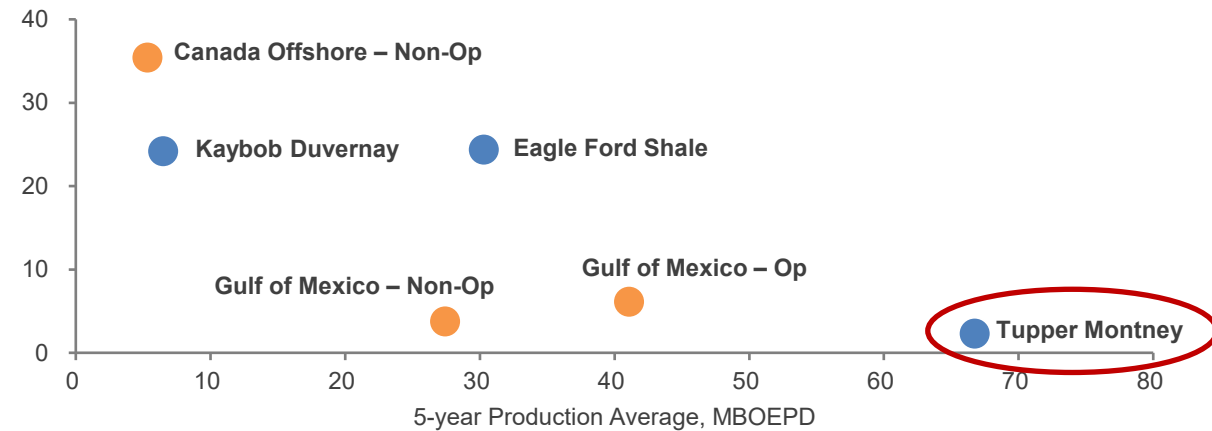
- Lowest greenhouse gas intensity asset in current portfolio

Annual Cumulative Cash Margin Per Well \$MM



Cash margins based on average price \$44 / WTI, \$1.78 / MCF AECO

Average 5-Year GHG Intensity by Asset Tonnes CO₂e / MBOE



Note: 5-year average intensity based on internal estimates

Tupper Montney Development

High Impact Development Drives Future Cash Flows

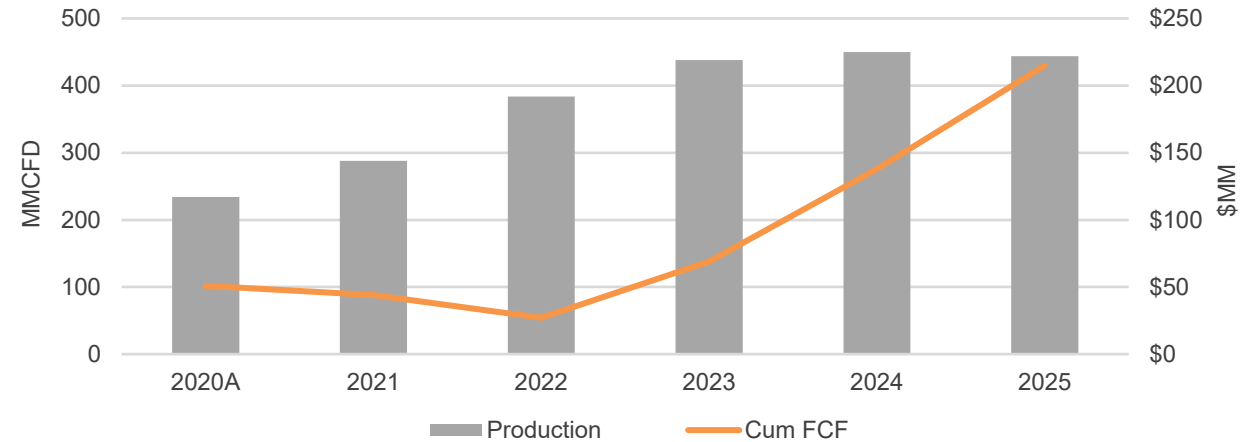
Tupper Montney Development Plan

- Commitment to infrastructure approved 2Q 2018; sanctioned 4Q 2020
- Free cash flow generated in 2020 of ~\$50 MM covers cumulative free cash flow requirement of \$24 MM for 2021 – 2022
- Average annual CAPEX of ~\$68 MM from 2020 – 2025
- Cumulative free cash flow of ~\$215 MM from 2020 – 2025

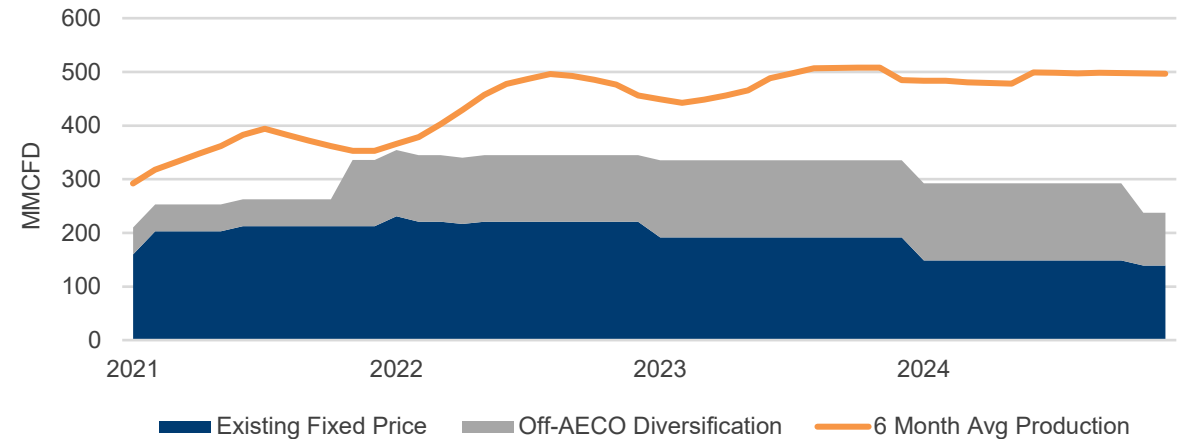
Low Execution Risk

- Increased average ultimate recovery to ~21 BCF / well
- Low subsurface risk from proven resource
- Ample existing take-away and infrastructure in place
- Mitigate price risk with fixed price forward sales contracts through 2024

Tupper Montney Production and Cumulative FCF



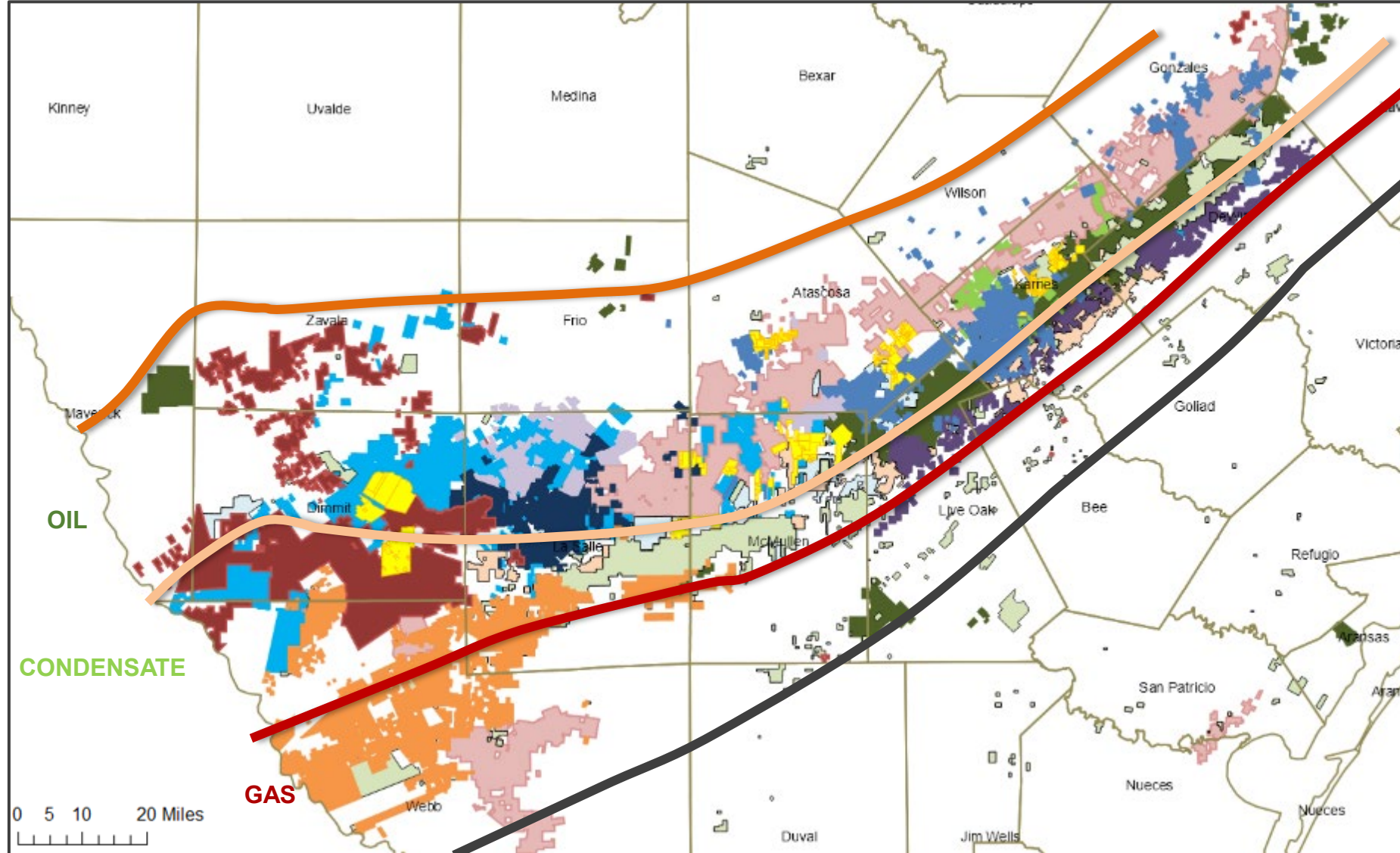
Tupper Montney Development Hedging and Production



Note: Free cash flow = operating cash flow (-) CAPEX (-) abandonment
 FCF based on average price \$1.98/MCF hedged, \$1.78/MCF AECO
 Note: Future production volumes based on current sanctioned plan

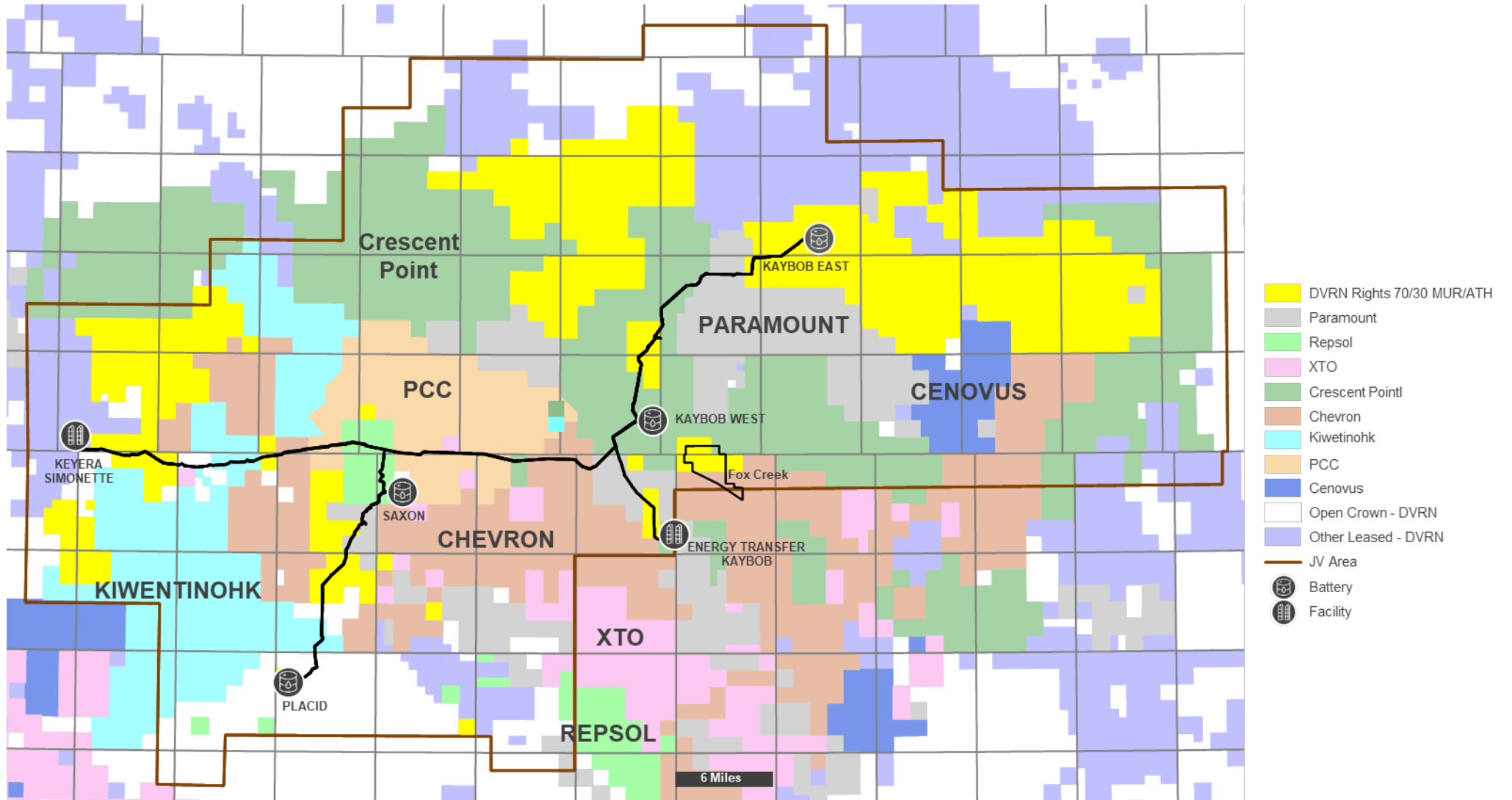
Eagle Ford Shale

Peer Acreage



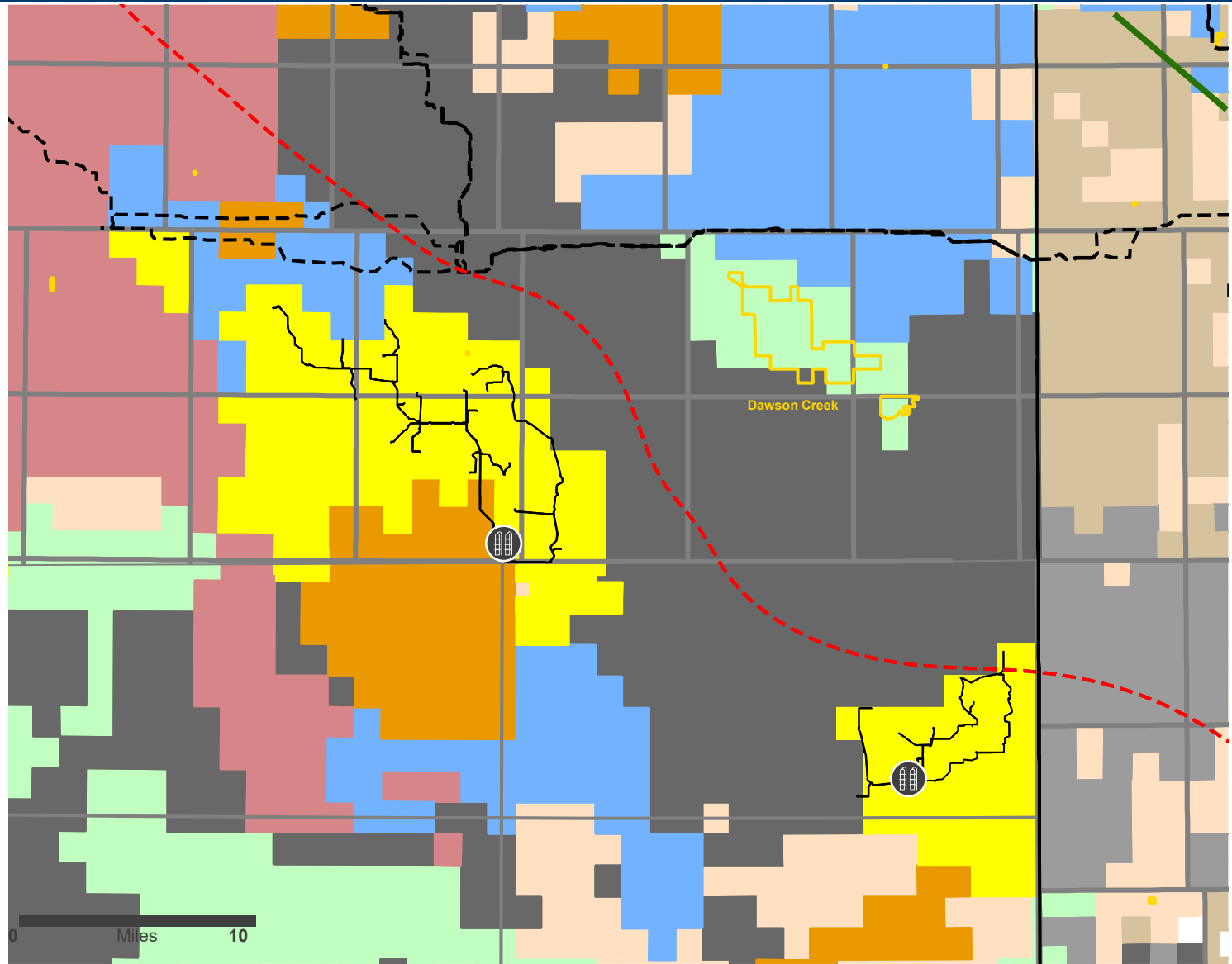
Kaybob Duvernay

Peer Acreage



Tupper Montney

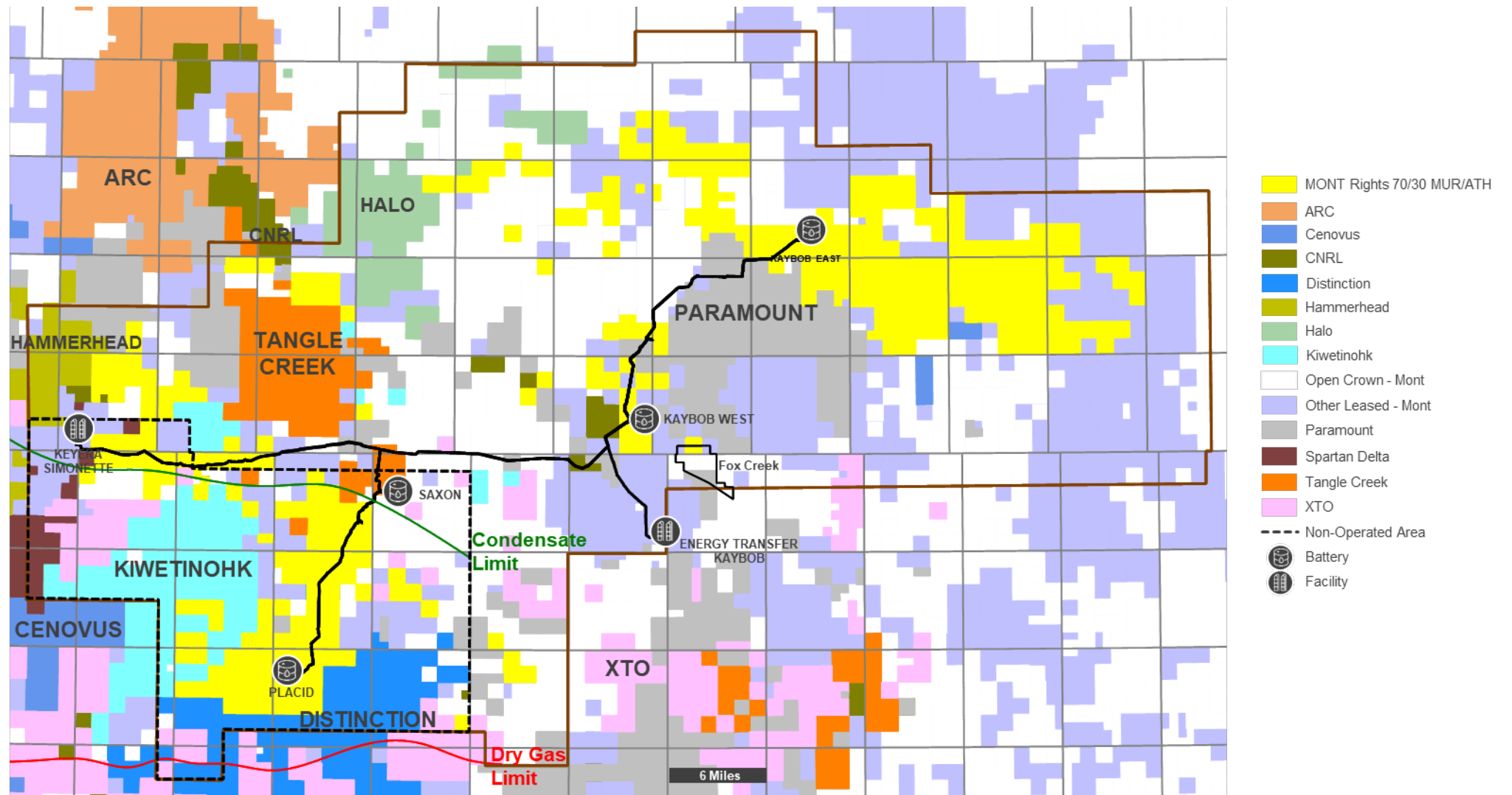
Peer Acreage



- Advantage Montney
- ARC Montney
- Birchcliff Montney
- Ovintiv Montney
- Tourmaline Montney
- Shell Montney
- Other Competitor Montney
- Open Crown - Montney
- Murphy Montney
- Dry Gas Limit
- TCPL Pipeline
- Murphy Pipeline
- Battery
- Facility

Placid Montney

Peer Acreage



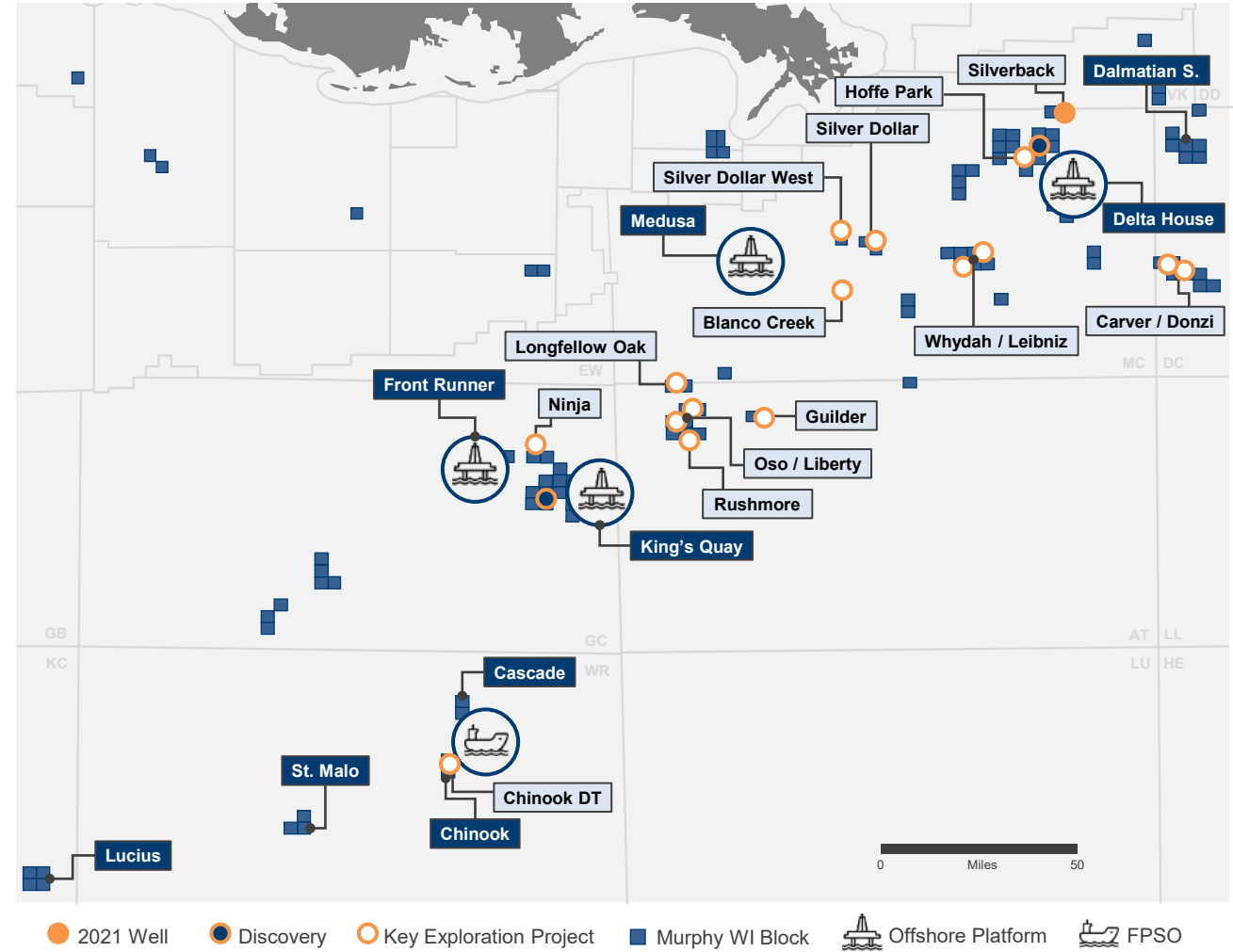
Gulf of Mexico

Murphy Blocks

PRODUCING ASSETS		
Asset	Operator	Murphy WI ¹
Cascade	Murphy	80%
Chinook	Murphy	80%
Clipper	Murphy	80%
Cottonwood	Murphy	80%
Dalmatian	Murphy	56%
Front Runner	Murphy	50%
Habanero	Shell	27%
Kodiak	Kosmos	48%
Lucius	Anadarko	13%
Marmalard	Murphy	27%
Marmalard East	Murphy	68%
Medusa	Murphy	48%
Neidermeyer	Murphy	53%
Powerball	Murphy	75%
Son of Bluto II	Murphy	27%
St. Malo	Chevron	20%
Tahoe	W&T	24%
Thunder Hawk	Murphy	50%

Note: Anadarko is a wholly-owned subsidiary of Occidental Petroleum
 1 Excluding noncontrolling interest

Gulf of Mexico Exploration Area



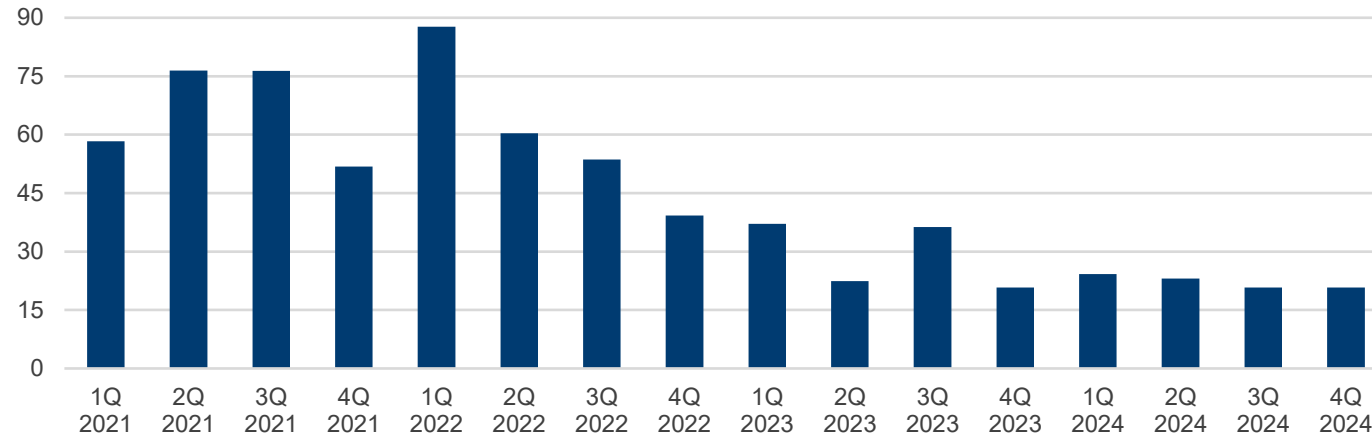
Gulf of Mexico

Major Projects CAPEX and Production Cadence

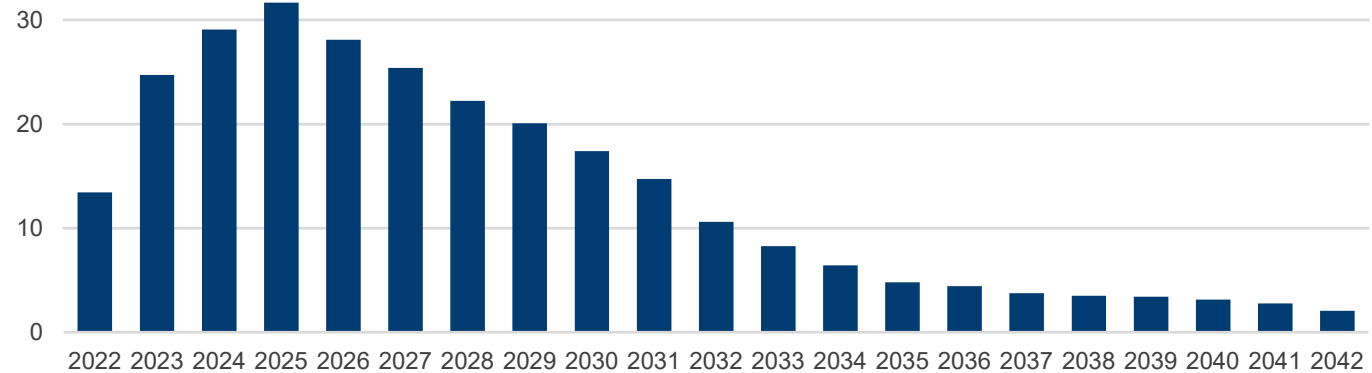


Major projects include Khaleesi, Mormont, Samurai and St. Malo waterflood

Major Projects Net CAPEX \$MM



Major Projects Net Production MBOEPD



2021 Exploration Plan

Potiguar Basin, Brazil

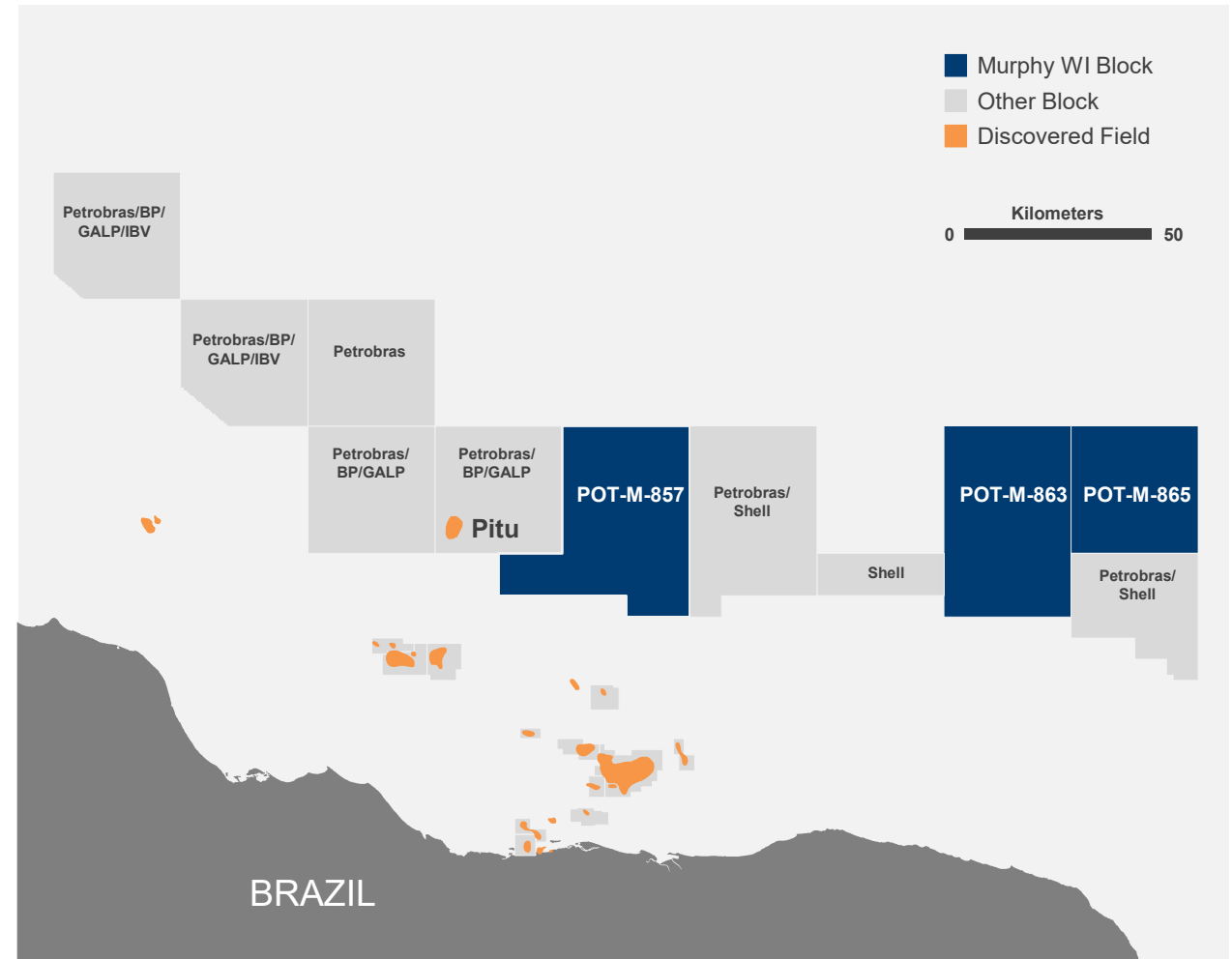
Asset Overview

- Wintershall Dea 70% (Op), Murphy 30%
- Hold WI in 3 blocks, spanning ~775 M gross acres
- Proven oil basin in proximity to Pitu oil discovery

Extending the Play into the Deepwater

- >2.1 BBOE discovered in basin
 - Onshore and shelf exploration
 - Pitu step-out into deepwater
- Interpreting final seismic data
- Targeting late 2022 to early 2023 spud

Potiguar Basin



2021 Exploration Plan

Salina Basin, Mexico

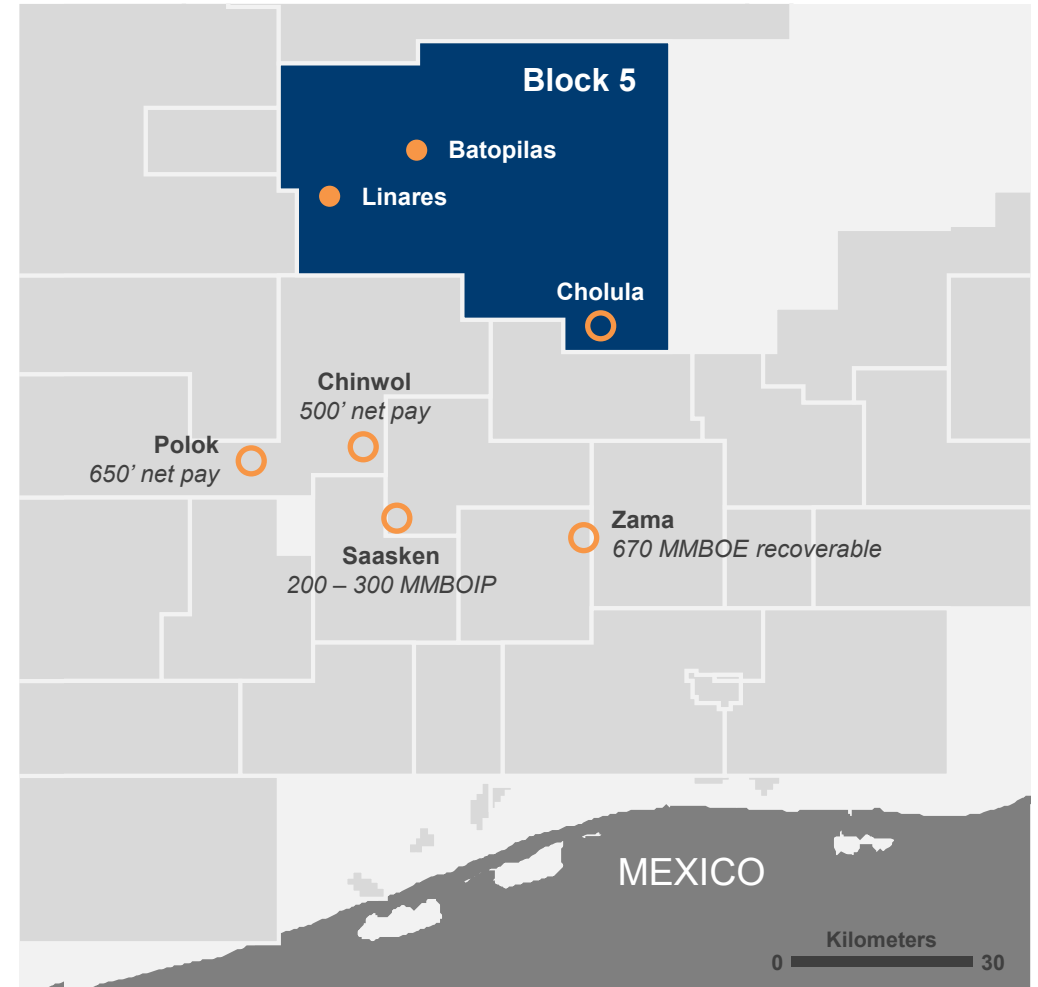
Block 5 Overview

- Murphy 40% (Op), Petronas 30%, Wintershall Dea 30%
- 34 leads / prospects
- Mean to upward gross resource potential
 - 800 MMBO – 2,000 MMBO
- Proven oil basin in proximity to multiple oil discoveries in Miocene section
- Targeting exploration drilling campaign in 2022
 - Initial prospects identified – Batopilas and Linares
 - Progressing permitting and regulatory approvals

Cholula Appraisal Program

- Discretionary 3-year program approved by CNH
- Up to 3 appraisal wells + geologic/engineering studies

Salina Basin



■ Murphy WI Block ■ Other Block ● Planned Well ○ Discovery

Development Update

Cuu Long Basin, Vietnam

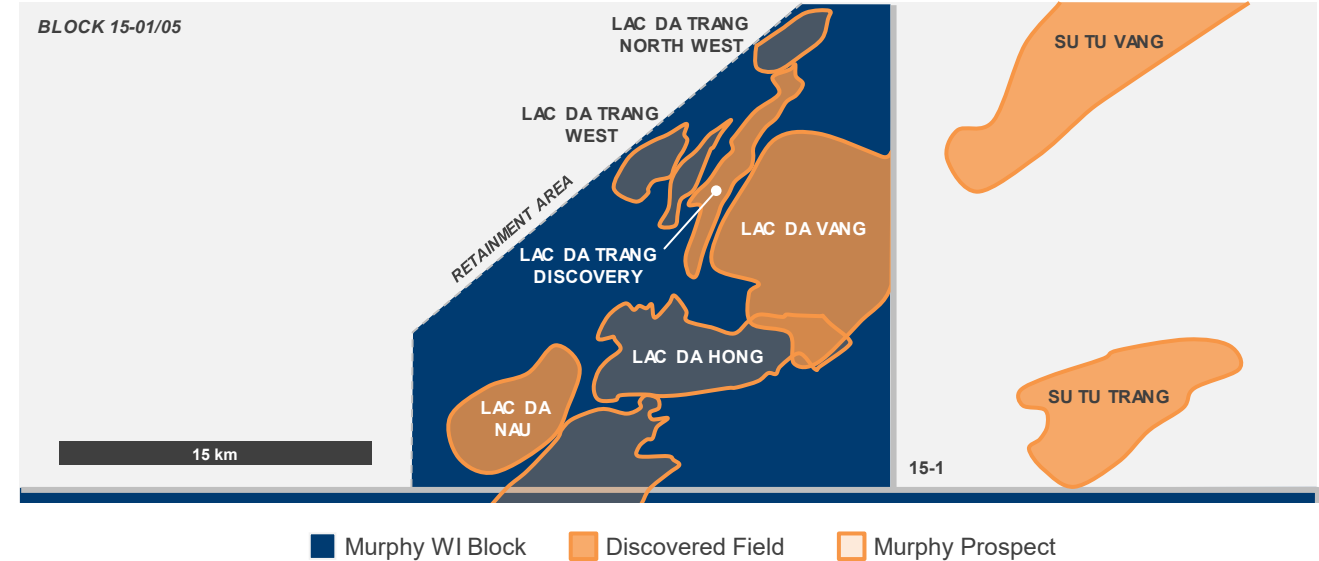
Asset Overview

- Murphy 40% (Op), PVEP 35%, SKI 25%

Block 15-1/05

- Received approval of the Lac Da Vang (LDV) retainment / development area
- LDV field development plan submitted to government
- LDT-1X discovery in 2019
- Maturing remaining block prospectivity
- LDT-1X discovery and other exploration upside has potential to add bolt-on resources to LDV

Cuu Long Basin



Exploration Update

Cuu Long Basin, Vietnam

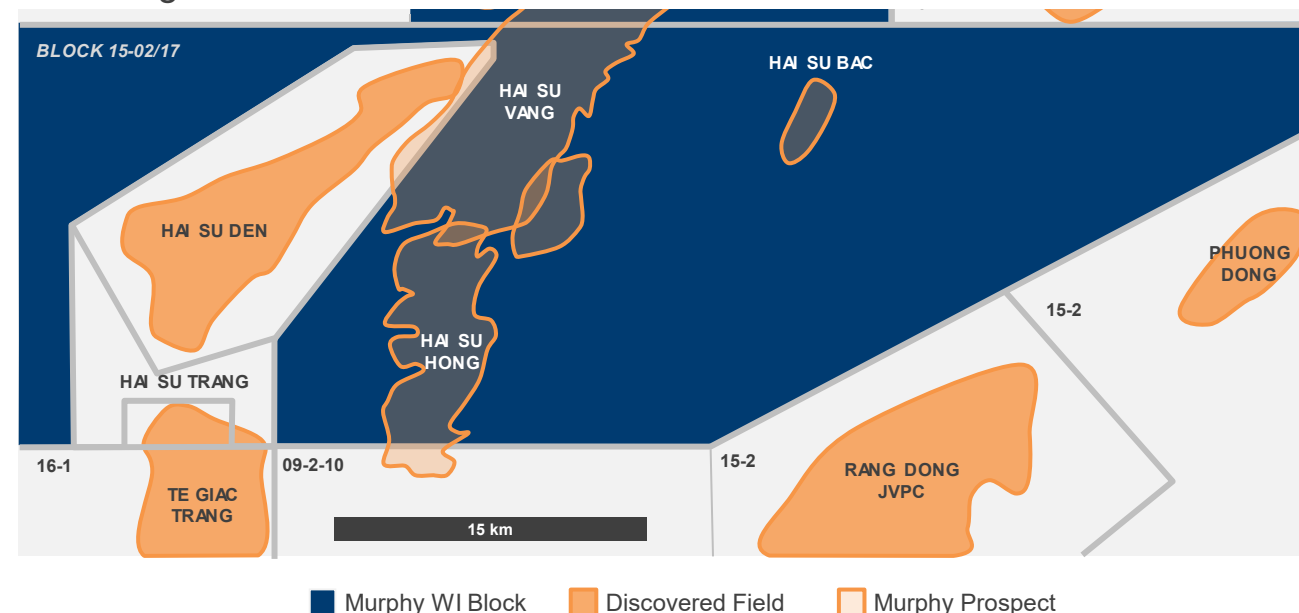
Asset Overview

- Murphy 40% (Op), PVEP 35%, SKI 25%

Block 15-2/17

- Signed joint operating agreement with partners in 4Q 2020
 - 3-year primary exploration period
 - 1 well commitment in 2022
- Seismic reprocessing, geological / geophysical studies ongoing

Cuu Long Basin





INVESTOR UPDATE

MAY 2021

ROGER W. JENKINS

PRESIDENT & CHIEF EXECUTIVE OFFICER