



DIVERSIFIED
energy

Corporate Presentation

May 2023



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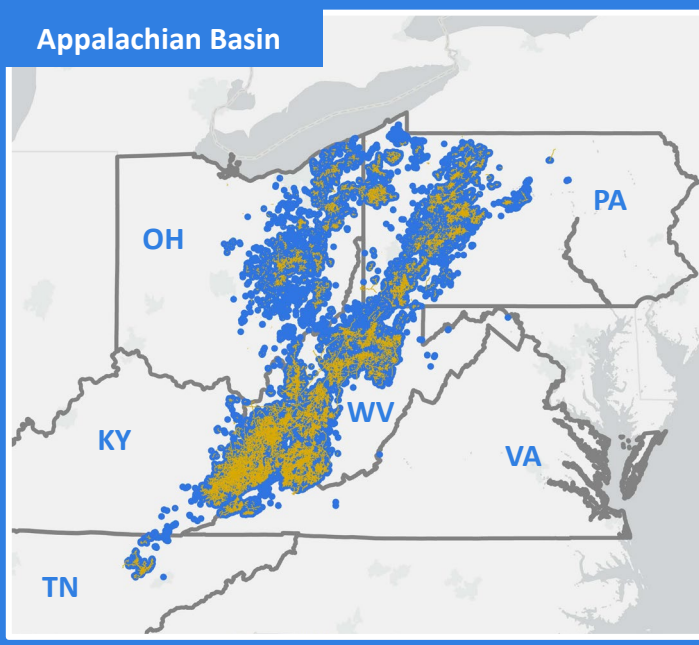
WHO ARE WE: OPERATOR OF U.S. ONSHORE DEVELOPED ASSETS

Appalachian Region:

Pennsylvania, West Virginia, Ohio,
Kentucky, Virginia, Tennessee

~60% of Production

Appalachian Basin

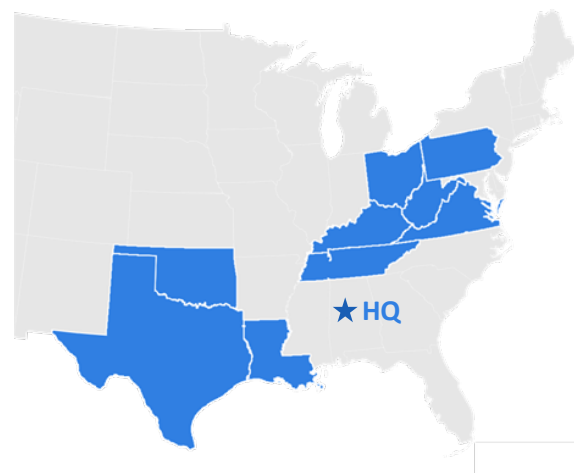
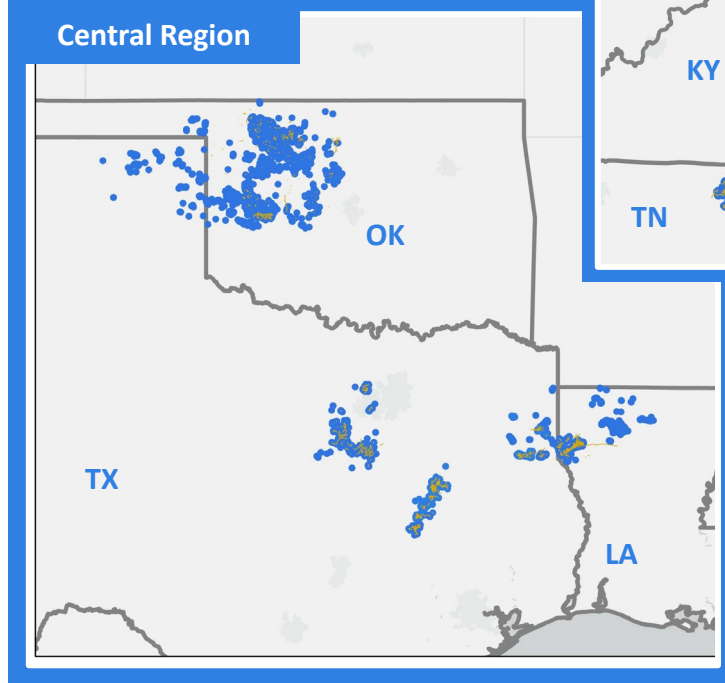


Central Region:

Oklahoma, Texas, Louisiana

~40% of Production

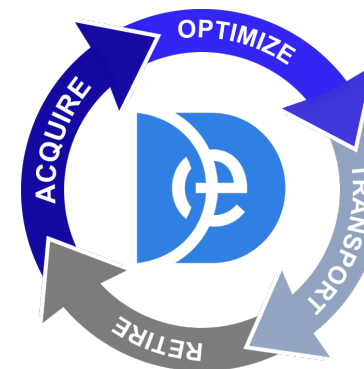
Central Region



- Upstream Assets
- Midstream Assets

A differentiated business model focused on:

- ✓ Optimising long-life, low-decline producing assets
- ✓ Strategically hedging to protect cash flow
- ✓ Vertically integrated to reduce expenses, expand margins
- ✓ Durable shareholder returns through the cycle
- ✓ Disciplined growth through low-risk PDP assets
- ✓ ESG goals naturally align with stewardship model
- ✓ **Expand Next LVL to become leader in safe, systematic well retirement**





EXECUTING ON STRATEGIC OBJECTIVES IN 1Q 2023



Achieved 54% Cash Margins^(a) (+4 pts vs. FY2022)

- ✓ 1Q23 Adjusted EBITDA of ~\$150 million and Annualized FCF Yield of ~37%^(b)



Produced 139 Mboepd of stable, low-decline assets

- ✓ Effective Smarter Asset Management programmes and Tanos II acquisition underpin activity



Reduced Unit Costs by 6% to \$10.46/Boe^(c)

- ✓ Lower cash costs driven by active asset management and lower variable commodity-linked expenses



Issued Sustainability Report: *Decarbonising While Delivering*

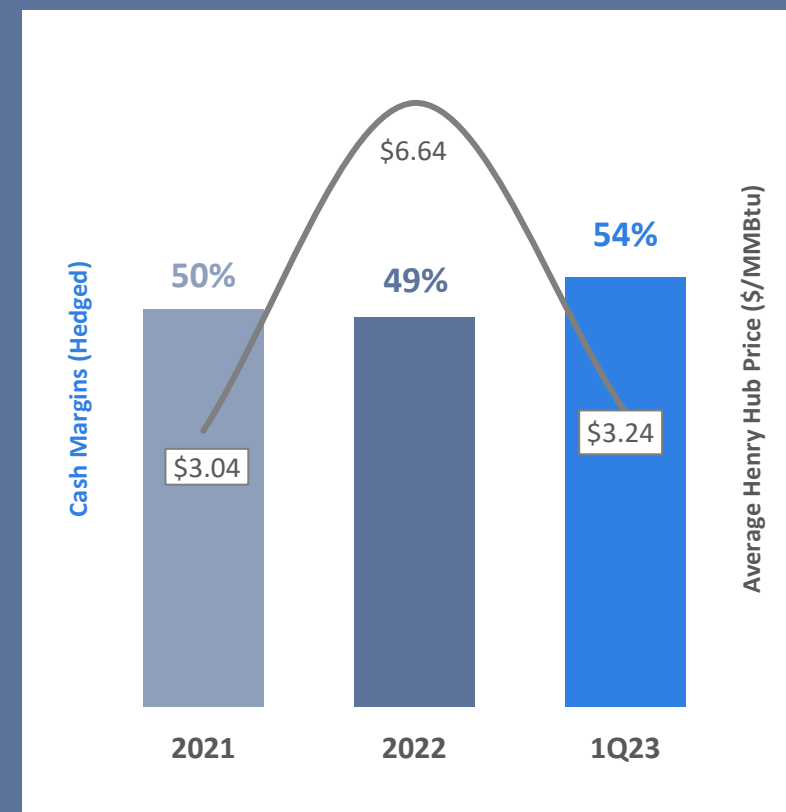
- ✓ Detailed safety wins, emissions reductions and community investment



Completed complementary acquisition of Tanos II assets

- ✓ Adds scale and improved margins within Central Region

Creating Sustainable Cash Flows thru Commodity Price Cycles



For Company-specific terms or Non-IFRS measures, please refer to the “Glossary of Terms”, “Alternative Performance Metrics” and “Non-IFRS Reconciliations” within the appendix and/or the Company’s 2022 Annual Report

a) Measured as Adjusted EBITDA, as a percentage of Total Revenue, Inclusive of Hedges; which includes the impact of derivatives settled in cash during the period

b) Annualized amount calculated using the Free Cash Flow per average share outstanding, divided by the average share price for the three months ended 31 March 2023 Free Cash Flow calculated as net cash provided by operating activities less expenditures on natural gas and oil properties and equipment and cash paid for interest; excluding the impact of working capital

c) Represents total lease operating costs plus recurring administrative costs. Total lease operating costs include base lease operating expense, owned gathering and compression (midstream) expense, third-party gathering and transportation expense, and production taxes; Excludes \$0.30/Boe of expenses attributable to Next LVL Energy



CREATING VALUE THROUGH TRANSPARENCY IN SUSTAINABILITY REPORTING



2022 Sustainability and Reporting Highlights

- ✓ Safety 1st: Achieved TRIR of **0.73**, a 35% reduction from 2020^(a)
- ✓ Reduced Scope 1 Methane Intensity (**1.2 MT CO₂e/Mmcfe**; -20% vs 2020)
- ✓ **\$507 million** of royalties paid to mineral interest owners
- ✓ Contributed **\$105 million** in state and local taxes
- ✓ Established **Community Giving and Engagement Programme**



Disclosed State-by-State
Economic Analysis



Enhanced Biodiversity
(TNFD) Disclosures



Published 2023 ESG
Performance Objectives



Expanded Climate Risk
(TCFD) Reporting

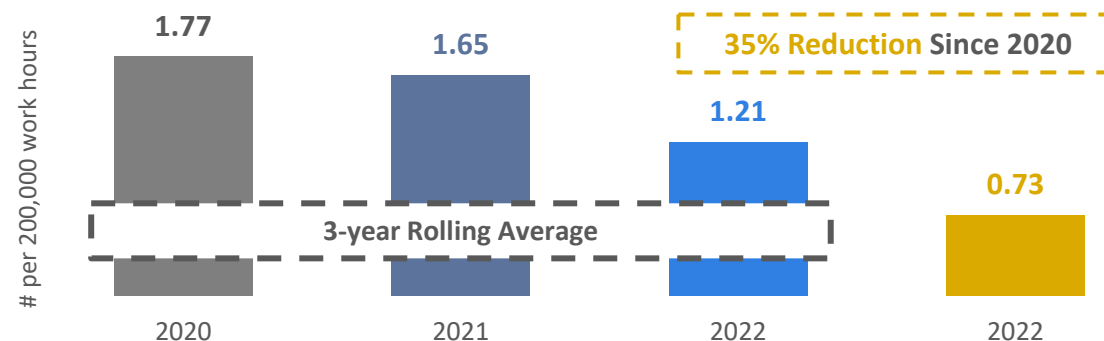


Achieved 'A' Rating
from MSCI Analytics

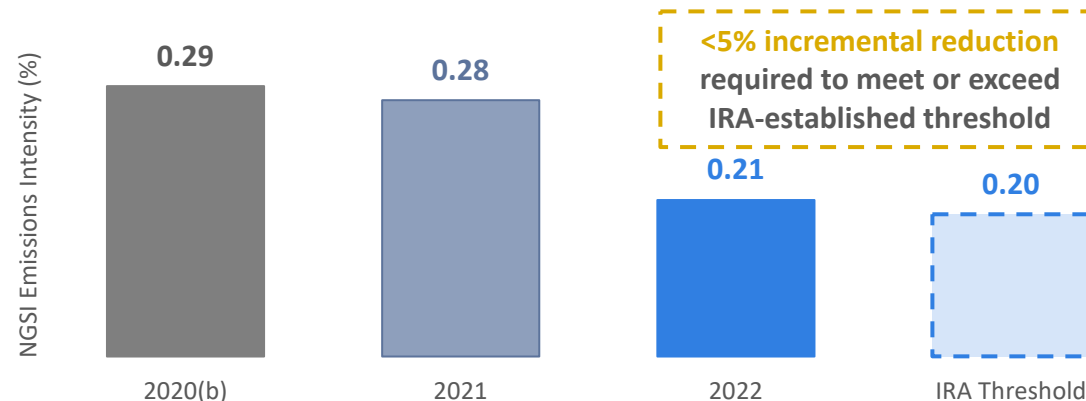


Awarded OGMP 2.0
Gold Standard

Total Recordable Incident Rate



Sustainability Strategy Drives Scope 1 Methane Intensity Lower



Learn more about Diversified's ESG practices, goals and disclosures online at div.energy/sustainability

a) Total Recordable Incident Rate; Percent reduction as compared to the three-year rolling average value for 2020

b) As first reported at year end 2021, emissions data for 2020 have been revised to incorporate the impacts of 2021 Project Fresh initiatives which focused on replacing theoretical emissions figures with more exact metrics as the result of direct measurement and emissions device inventory processes



HEDGING STRATEGY MITIGATES COMMODITY PRICE VOLATILITY

De-Risk Commodity Revenues

Differentiated hedging strategy mitigates commodity price risk by strategically locking in future cash flows

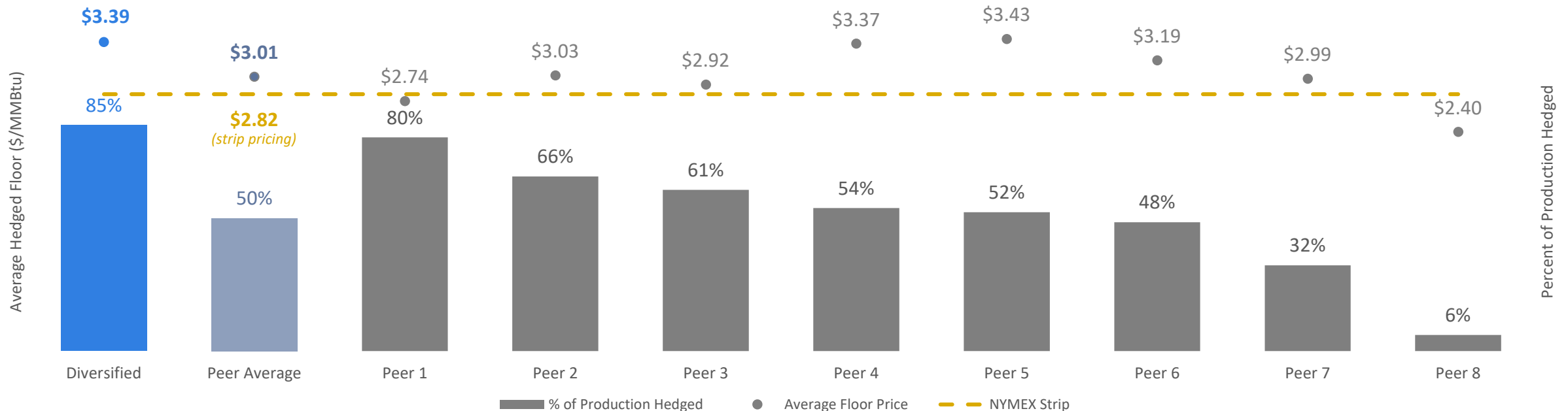
Generate Robust Margins

Scale, asset density & vertical integration reduce operating costs, create runway for consistent cash margins

Sustain Shareholder Returns

Shareholder returns are independent of commodity prices, ensuring full-cycle profitability and value creation

Diversified Leads Peers in 2023 Price Protection



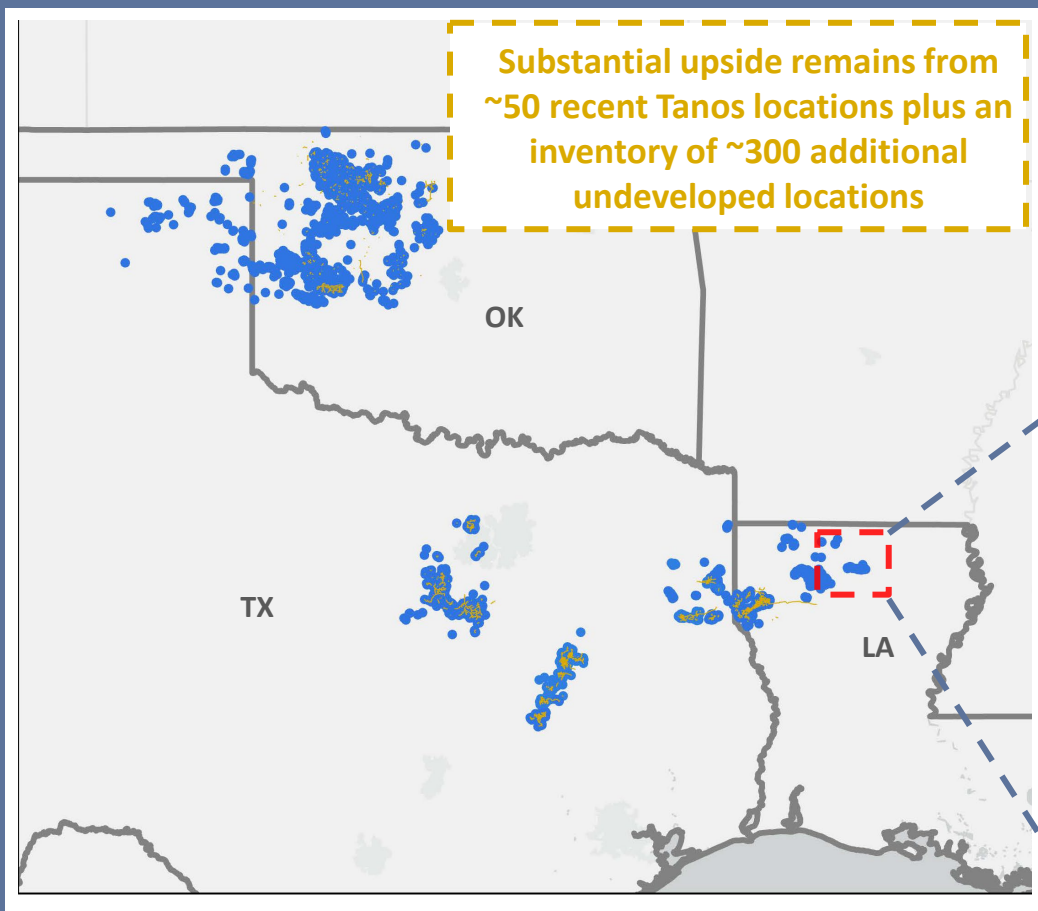
Diversified hedge position as of 10 March 2023, please refer to the appendix for more information;
NYMEX Strip for 2023 includes settled contracts for January-March 2023 and futures pricing for April-December 2023; Source: Bloomberg
Peers include AR, CHK, CNX, CRK, GPOR, RRC, SWN and Ascent Resources; Source: Company Presentation and Enverus



EXTRACTING VALUE ON UNDEVELOPED ACREAGE (ILLUSTRATIVE EXAMPLE)

Advantageous Joint Venture

Accretive opportunity to add upside



Monetization of economic locations

~\$25 million (50/50 split to Oaktree) and \$8-\$12 million carry on future development

Realization of value for undeveloped acreage

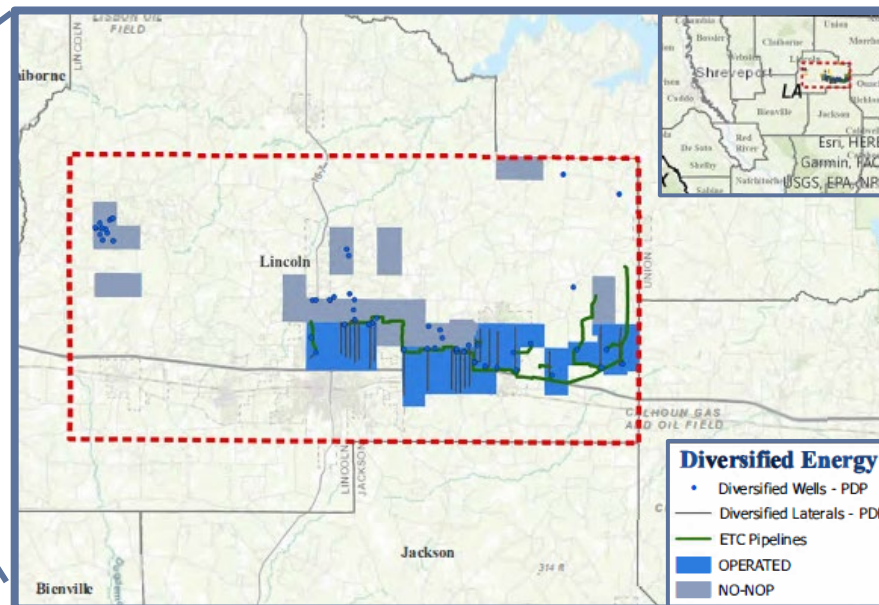
PV12 to PV15 value on PDP and \$1,000-\$1,500 per net acre on undeveloped acres

Adding incremental upside

There were no near-term plans to develop this acreage joint owned with Oaktree

Further development opportunity

If successful, intention is to develop the rest of the field



~7,500
Net Acres

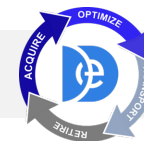
1-4

Development Wells in
Cotton Valley

50%
PDP Production



DELIVERING RECORD PRODUCTION AND RESERVES



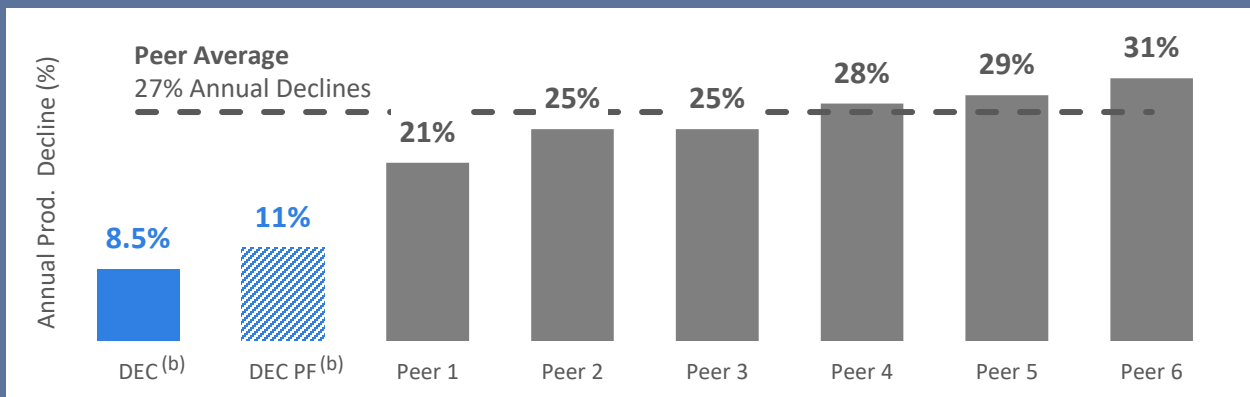
Central Region Growth Drives Record Production

- ✓ ~75 Mboepd of net production added since entry to region
- ✓ ~40% of March 2023 production from Central Region assets
- ✓ Appalachia assets continues to produce at steady, stable rates

Recent Acquisitions Support Reserves Replacement, Growth

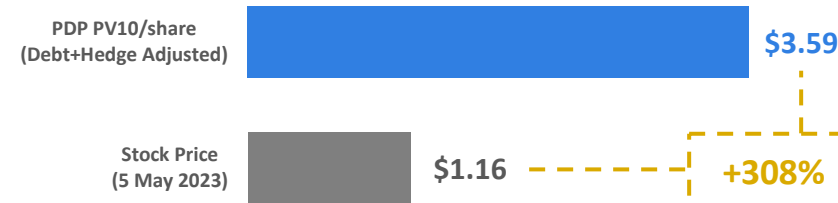
- ✓ Increased PDP Reserves by 80 MMboe, lifts PV10 by 68% since 2021
- ✓ Low-cost workover and recompleting projects add incremental uplift

Smarter Asset Management Sustains Industry-Low Declines^(a)



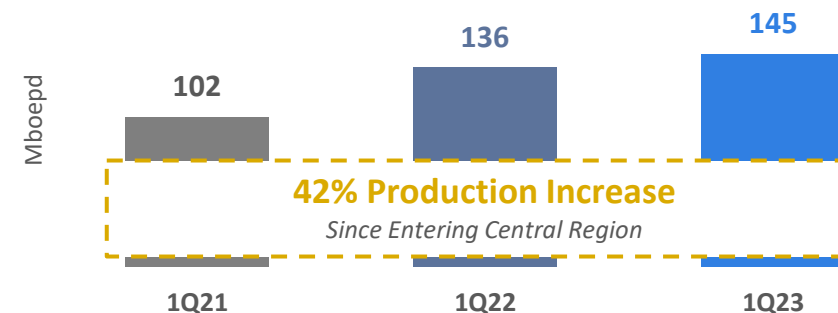
PV10 Value of PDP Reserves per Share^(c)

302% Premium to Current Share Price



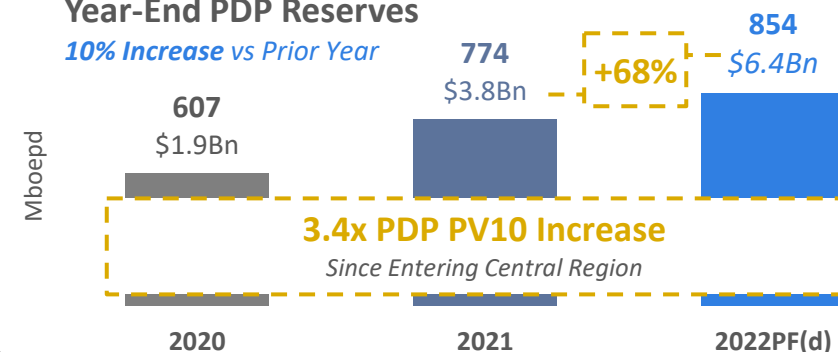
March Exit Rate of Production

7% Increase vs Prior Year



Year-End PDP Reserves

10% Increase vs Prior Year



a) Peer declines calculated using estimated annual declines for the twelve-month period ended March 2023; Peers include AR, CHK, EQT, GPOR, RRC and SWN; Source: Enverus

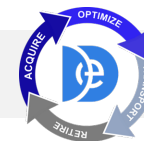
b) DEC as previously announced on 31 January 2023; DEC Pro Forma ("DEC PF") includes the pro forma impact of the Tanos II acquisition using anticipated PDP production declines for the 12-month period ended 31 January 2024

c) Calculated as the PV-10 of PDP Reserves, net ARO, Net Debt and Net Fair Value of Derivatives at 31 December 2022, pro forma for the previously announced Tanos II acquisition; Shares outstanding and share price as at 01 May 2023;

d) 2022PF calculated as year-end PDP Reserves at 31 December 2022, adjusted for the pro forma impact of the previously announced Tanos II acquisition



EXECUTING PROVEN ACQUISITION STRATEGY TO DRIVE VALUE



Upstream

2022 Acquisitions

Improving operating scale and density in the Central Region

- ✓ Added ~**13 Mboepd** of production and **49 MMboe** of reserves
- ✓ Strategically **consolidated assets within operating footprint**
- ✓ Purchased at a combined **2.2x NTM EBITDA** multiple^(a) and a **25% discount to PDP PV-10** of \$399 million^(a)
- ✓ Centralized administrative **support provides immediate synergies** without the need for incremental costs

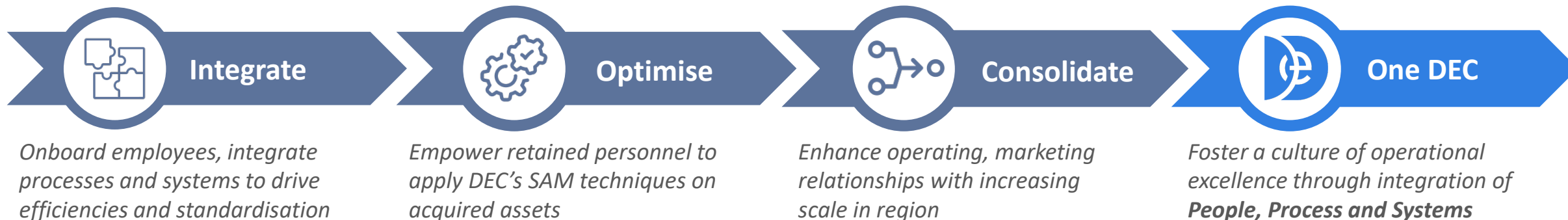
Midstream

2022 Acquisitions

Enhancing margins and increasing control over product flow

- ✓ **95% of system volumes** from Diversified-operated assets
- ✓ Combined purch. price represents **2.5x cash flow multiple^(b)**
- ✓ Owned systems provide **improved product flow** and **incremental third-party revenues** (80% capacity remaining)
- ✓ Owned NGL processing facility in Louisiana **reduces costs** and **adds revenue-generating potential** (operating at 25% capacity)

Implementing Standardised Post-Acquisition Processes



a) Calculated using the aggregate NTM EBITDA estimates, Net Purchase Price and respective PDP PV-10 for the East Texas and ConocoPhillips acquisitions, as previously announced

b) Calculated using the aggregate NTM cash flow estimate and Net Purchase price for midstream systems and processing facilities acquired in 2022



TANOS ENERGY ACQUISITION HIGHLIGHTS



Acquisition Valuations

~PV17 2.3x ~PV28 20% 19%

Equivalent PDP Purchase Price^(a) PDP Purchase Price Multiple^(b) PDP+ Undeveloped^(a) Accretive to Adj. FCF Accretive to Adj. EBITDA



Adds Scale-Driving Synergies

Assets are contiguous with owned assets, increasing density and enhancing scale; Improves current unit-cost metrics



Expands Undeveloped Upside Opportunities

~50 undeveloped locations with a PV10 of ~\$280MM^(c) complementary to ~300 previously acquired locations in region



Demonstrated Emphasis on ESG

Continuous monitoring of emissions on >90% of production complements existing emissions detection activities

Acquisition Highlights

Purchase Price (\$MM) ^(d)	\$250
Estimated NTM EBITDA (\$MM) ^(e)	\$107
Acquired PDP Reserves (MMBoe and Bcfe) ^(f)	25 / 152
PV10 of Acquired Producing Reserves (\$MM) ^(f)	\$312
PV10 Undeveloped Reserves (\$MM) ^(c)	\$279
Current Production (Mboepd / MMcfepd)	17 / 101
Total Cash Costs (\$/Boe) ^(g)	\$5.10 - \$5.70
Total Cash Costs (\$/Mcfe) ^(g)	\$0.85 - \$0.95
Estimated EBITDA Margin ^(e)	~80%

Undeveloped Location Inventory Adds Substantial Upside

May be monetized or opportunistically developed

■ PDP + Scheduled(a) ■ SAM Opportunity(b) ■ Undeveloped(c)



a) Approximate value calculating using the acquisition purchase price and reserves economics data as detailed within footnotes (c) and (d)

b) Calculated as acquisition purchase price (see footnote (d)) divided by the estimated Next Twelve Months ("NTM") EBITDA

c) Using NYMEX strip pricing as of 12 January 2023 for producing reserves and as of 12 December 2022 for undeveloped reserves; Producing reserves includes PDP and wells scheduled for completion before or immediately following the expected close date; Undeveloped reserves exclude reserves associated with wells scheduled for completion before or immediately following the expected close date

d) Purchase price excludes ~\$7 million for hedge positions to be acquired from the seller with a value of ~\$10 million as of 27 January 2023

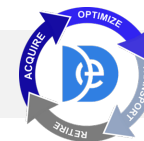
e) Reflects the Acquisition's estimated NTM EBITDA for PDP wells and wells scheduled for completion before or immediately following the close date; assumes historical cost structure using NYMEX strip as of 12 January 2023; does not assume any post-acquisition synergies; Estimated EBITDA Margin calculated as the NTM estimated EBITDA as a percentage of total revenue

f) Measured at acquisition effective date of 1 February 2023 and using NYMEX strip pricing as of 12 January 2023; Producing reserves includes PDP and wells scheduled for completion before or immediately following the expected close date

g) Utilizes historical cost structure and assumes no immediate synergies; Represents Base LOE, Gathering and Transportation costs and Production Taxes and G&A



SMARTER ASSET MANAGEMENT PROVIDES ONGOING VALUE



RTP Wells Return to Production

- ✓ Turn acquired idle wells back into production and cash flows
- ✓ **~340 wells RTP'd** in Central Region during 2022
- ✓ Typically **low-cost, high return** RTP is accretive to deal economics



Workovers and Recompletion

- ✓ Enhance production with low-cost, capitalised maintenance
- ✓ **305 workovers completed** in Diversified's Central Region
- ✓ High return projects feature low **payback of just 2 months**



Optimisation of Central Compression

- ✓ Leverage scale to reduce midstream operating costs
- ✓ **\$1.5 million in annualized savings** generated during 2022
- ✓ Continued **growth creates add'l opportunity** for optimisation



Re-Route Appalachian Volumes

- ✓ Redirect gas volumes to alternative processing facility
- ✓ **Increases sold NGL volumes by ~10%** of 2022 production^(a)
- ✓ Re-route creates **annualized revenue uplift of ~\$15 million^(a)**

Value Added Workovers

Low Cost

Average ~\$45K per well

Increased Production

Added ~40 Mmcfe per day *(gross)*

High Returns

2-month payback; +175% return

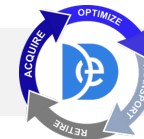
Impact

~10% uplift in Central Region production *(net)*



Daily Operating Priorities

a) Based on projected increase in sold NGL volumes in comparison to recorded NGL production for FY2022; Revenue estimates based on volumetric uplift and current strip pricing



Multiple Operating Regions = Multiple Resource Pools

Expansion to the Central Region increased the potential for knowledge-sharing and transfer of available inventory

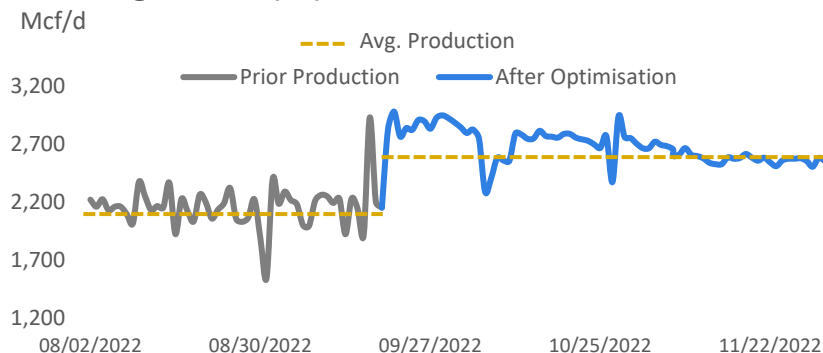
Operating Scale Results in Smarter Asset Management Win

Operations identified the ability to utilize surplus capillary string equipment in Central Region for well optimization in Appalachia

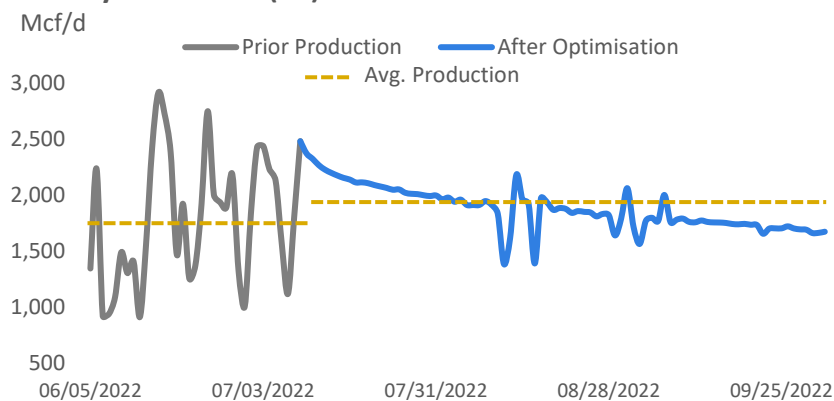
Capillary String Well Treatment Applied in Appalachia

Implementation in Appalachia was highly successful and multiple well sites are under review for continued utilisation

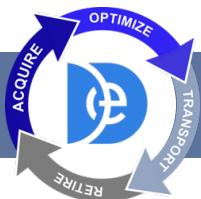
West Virginia Well (Hz)



Pennsylvania Well (Hz)

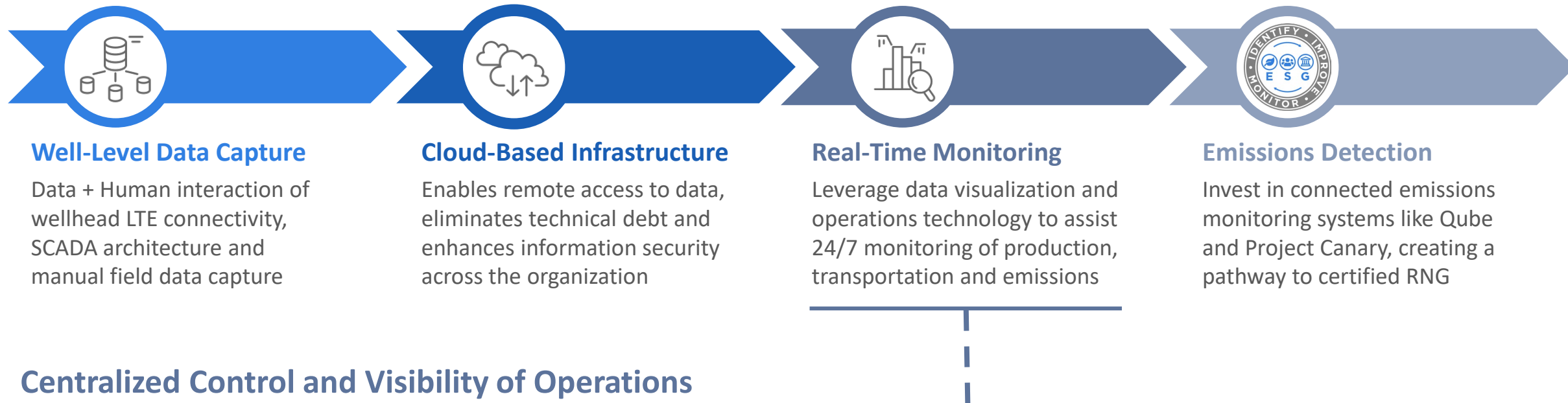
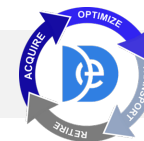


Capillary string well treatments improves production without the need for workover rigs or artificial lift systems





OPERATIONAL INSIGHTS DRIVEN BY TECHNOLOGY INVESTMENTS



Upstream Systems

- ✓ **Mitigates impact** of production disruptions
- ✓ **Assists production optimisation** activities
- ✓ **Enhances EHS awareness and responses**
- ✓ **Capacity to expand** to additional owned systems

Midstream Systems

- ✓ Enhances **visibility** to product volume and flow
- ✓ **Provides centralized oversight** for multiple systems
- ✓ Informs gas control technicians with **real-time reports**
- ✓ **Capacity to expand** to additional owned systems



Differentiated Outlook on Asset Retirement

Stewardship from acquisition to retirement ensures sustainable operations for the lifetime of assets



Efficiencies Obtained through Operating Scale

Full suite of service capabilities creates unique capacity for efficient and effective asset retirement



Uniquely Situated for Program Management

Full-scope services from permitting to plugging enhance ability to deliver internal efficiencies and provide third-party services to states and other operators



Strategy Driven by Innovation not Repetition

Cumulative experience from internal and third-party retirement provides process enhancement insights

Positioned to Lead in Appalachian Asset Retirement

As a wholly-owned subsidiary of Diversified, Next LVL Energy is strategically advantaged among Appalachian retirement companies:

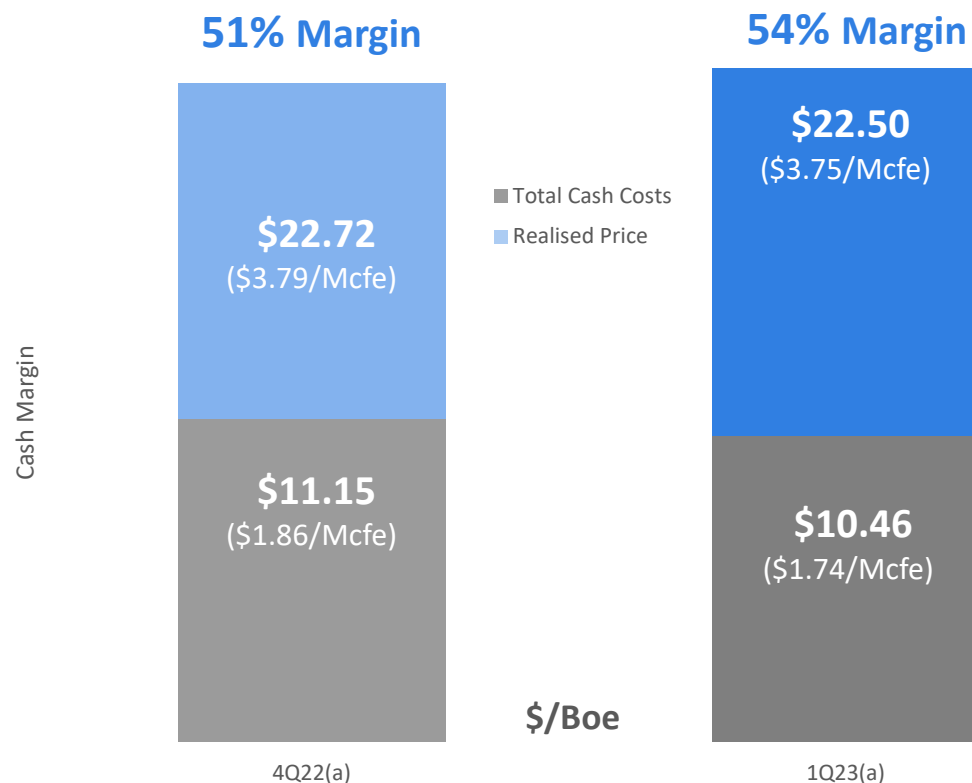
- ✓ Financial stability
- ✓ Corporate support of FTSE 250-listed operator
- ✓ Positioned to innovate well retirement techniques
- ✓ Strong industry and state relationships



BUILT TO DELIVER STABLE MARGINS THROUGH VOLATILE COMMODITY CYCLES

Realizing Consistent >50% Margins

Increases to realized pricing generate stable margins amidst commodity price-driven cost inflation



Hedge Strategy Sustains Realised Pricing

Consistent application of price protection limited exposure to 40% drop in natural gas prices

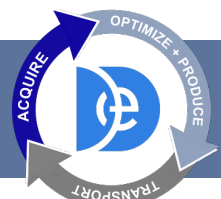
Expanding Margins on Decreased Costs

6% decrease in Total Cash Costs per unit drives margin improvement over sequential quarters

Vertically Integrated for Cost Insulation

Integrated marketing, midstream and asset retirement limit inflationary cost pressure

Consistent cash margins underpin sustainable value creation and return for shareholders



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a) 4Q22 excludes \$0.28/Boe (\$0.05/Mcfe) of revenue and \$(0.34)/Boe (\$(0.06)/Mcfe) of expenses attributable to Next LVL Energy; 1Q23 excludes \$0.35/Boe (\$0.06/Mcfe) of revenue and \$(0.28)/Boe (\$(0.05)/Mcfe) of expenses attributable to Next LVL Energy



HEDGING STRATEGY UNDERPINS FULL-CYCLE PROFITABILITY, CASH GENERATION

Mitigating Price-Cycle Volatility

Hedging strategy has produced robust Cash Margins of ~50% since Feb 2017 IPO

Supporting Low-Cost Deleveraging

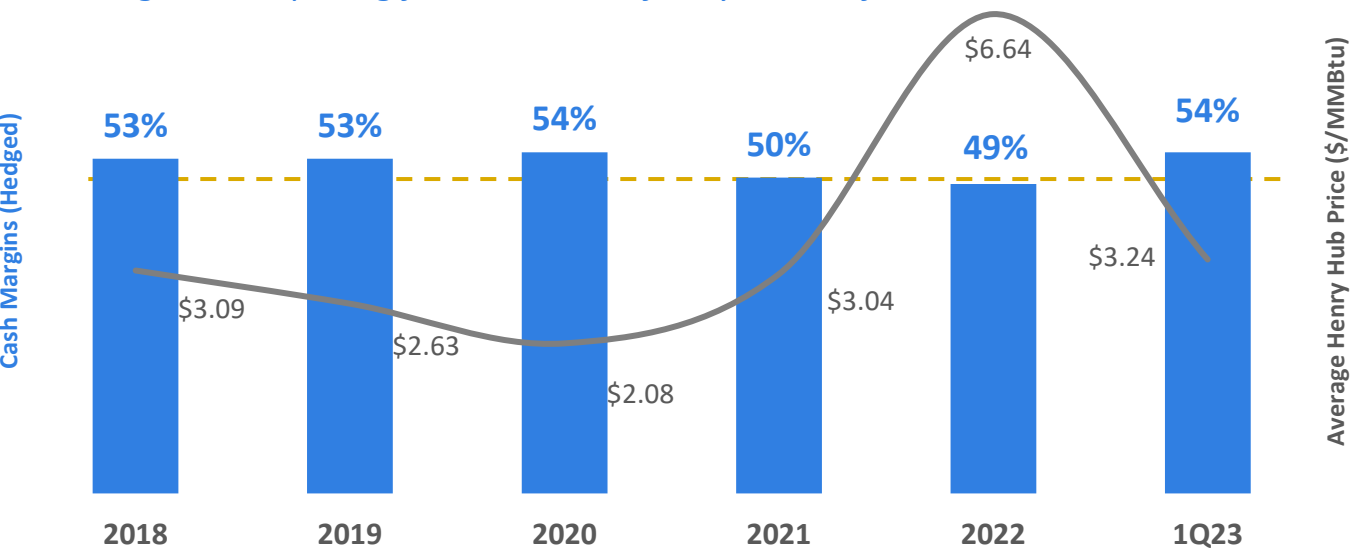
Selectively optimize portfolio to align with amortising asset securitization strategy

Ensuring Shareholder Returns

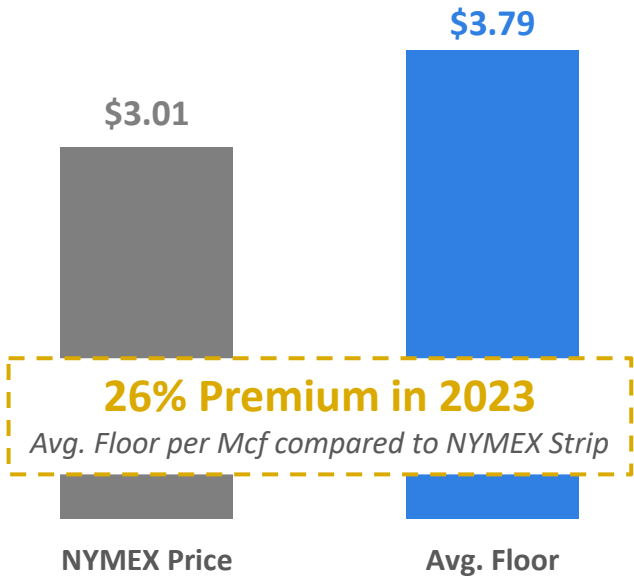
Enhance line-of-sight for long-term value creation by de-risking commodity revenue

Hedge Strategy Reduces Sensitivity To Commodity Price Volatility

Protecting realized pricing for sustainable, full-cycle cash flows



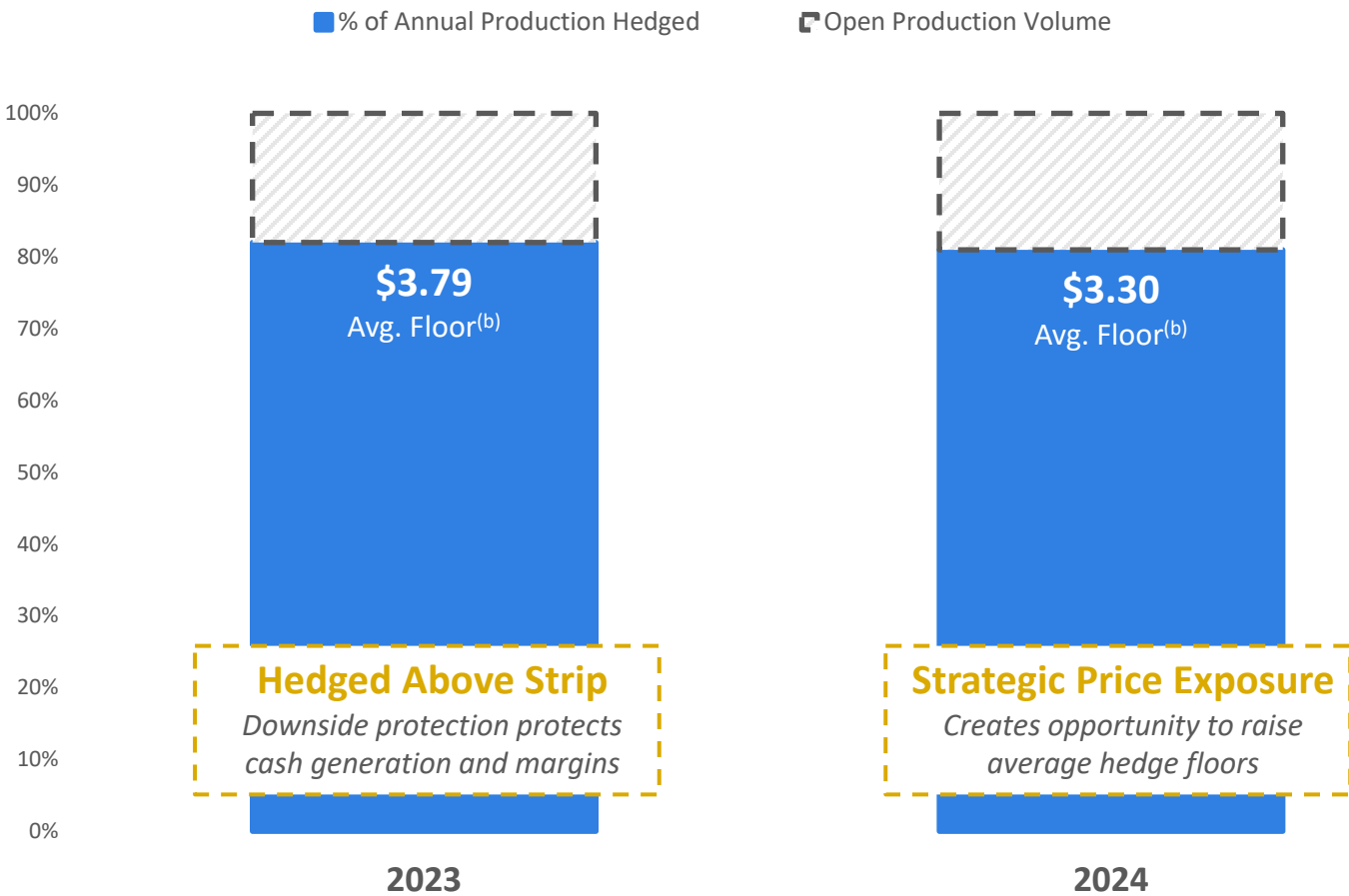
2023 Hedged Pricing Materially Above NYMEX Strip^(a)



Source: Company Data; Bloomberg
a) As of 01 May 2023; Represents 2023 NYMEX Henry Hub strip (including settled months) and average natural gas hedge floor price in \$/Mcf; MMBtu have been converted to Mcf using corporate energy richness factor of 1Mcf = 1.07 MMBtu

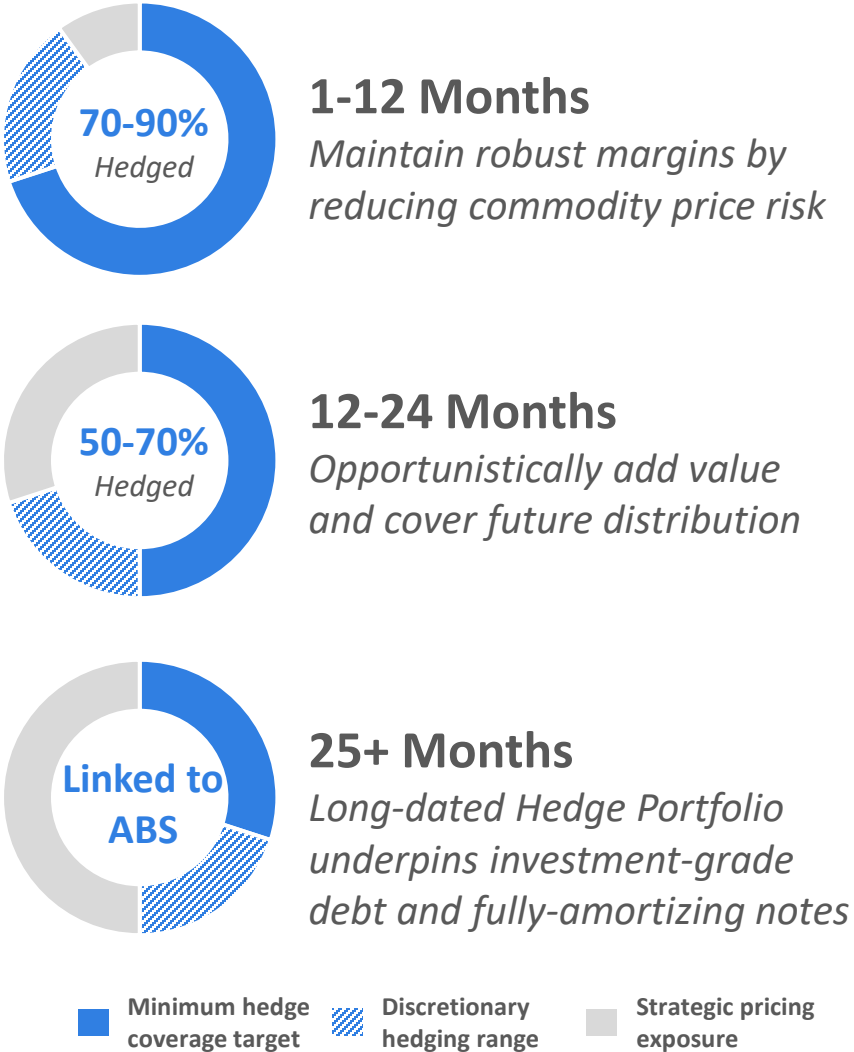
Summary Natural Gas Hedging Position

Average Hedge Floors in \$/Mcf^(a)



Average Strip Price ^(c)	\$3.01	\$3.81
------------------------------------	--------	--------

Rolling Hedge Coverage Targets^(c)



a) Illustrative percent of production hedged calculated using published derivatives portfolio and illustrative production volume, calculated using reported production and declines pro forma for the impact of the previously announced Tanos II acquisition;
 b) Calculated as the consolidated average floor price for natural gas financial derivatives as of 01 May 2023; MMBtu have been converted to Mcf using corporate energy richness factor of 1Mcf = 1,07 Mmbtu
 c) Source: Bloomberg; Reflects annual average NYMEX Henry Hub pricing, as of 01 May 2023 and includes settled contract values for January 2023 – May 2023
 d) Rolling hedge targets relate to discretionary hedging volumes not associated with the long-term hedging profile of cash flows and assets underlying Diversified’s Asset Backed Securitisations

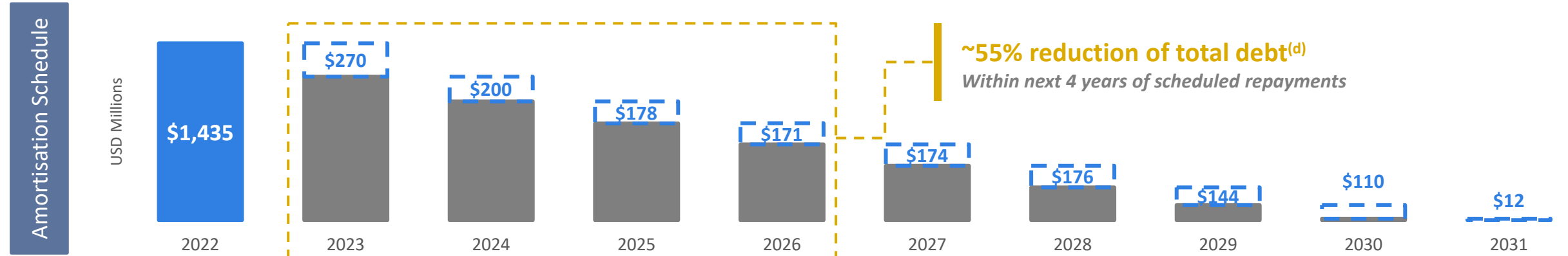
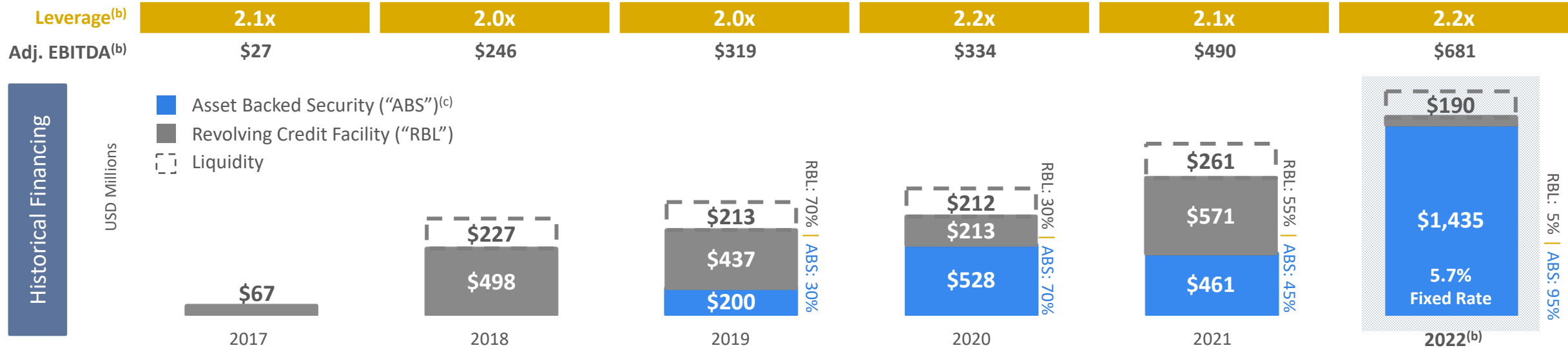


SIMPLE, LOW-COST, HIGHLY-AMORTIZING STRUCTURE

Low, ~5% fixed rates provide cost of capital advantage

Liquidity-enhancing long-term financing alternative to RBL

ESG-linked Financing^(a) reflect commitment to sustainability



For Company-specific terms or Non-IFRS measures, please refer to the "Glossary of Terms", "Alternative Performance Metrics" and "Non-IFRS Reconciliations" within the Company's 2022 Annual Report

a) For ABS III and ABS IV, coupon will be tied to ESG Assessment from Moody's; For ABSV and ABS VI coupon will be tied to achieving certain emission reduction targets reported annually in the Company's Sustainability Report

b) Calculated as Pro Forma Net Debt-to-Hedged Adjusted EBITDA for the respective periods presented; 2022 includes pro forma adjustments for the recently announced Tanos II acquisition

c) ABS category includes fully amortising Secured Term Loan

d) As reported at 31 December 2022, includes Diversified's amortising debt, outstanding balance on the Company's Revolving Credit Facility and Other Debt



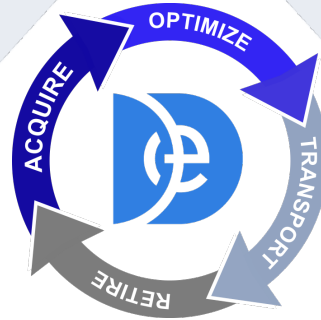
Resilient core business and seasoned management that leverages competencies into attractive opportunities with a track record of turning liabilities into assets and delivering returns

Be the consolidator of mature natural gas producing assets in North America

Own the value chain through vertical integration from production to end of life

Deploy Smarter Asset Management to increase production, reduce emissions and extend well life

Expand retirement capacity, evolve carbon capture opportunities & lead well retirement innovation



**Maximize
Shareholder Value**





DIVERSIFIED
energy

DIVERSIFIED

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Appendix



DIVERSIFIED ENERGY PROFILE

LSE: DEC (FTSE250)

Market and Trading Summary | 10 March 2023

(in millions, except share price)

Share Price £0.95 / \$1.19

Market Cap (MM) £920 / \$1,157

Net Debt^(a) (MM) £1,148 / \$1,435

Enterprise Value (MM) £2,068 / \$2,592

Leverage^(b) (MM) 2.3x

Diversified Asset Highlights

(March 2023, except where highlighted)

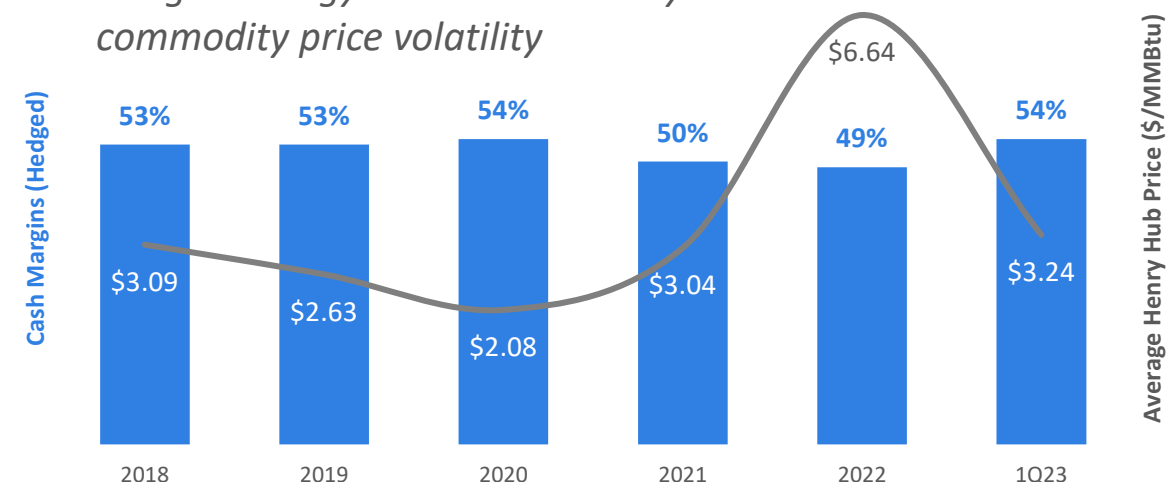
Net Daily Production (Mboepd / MMcfepd) 145 / 872

Natural Gas Production Mix ~85%

PDP Reserves^(c) (MMBoe / Tcfe) 854 / 5.1

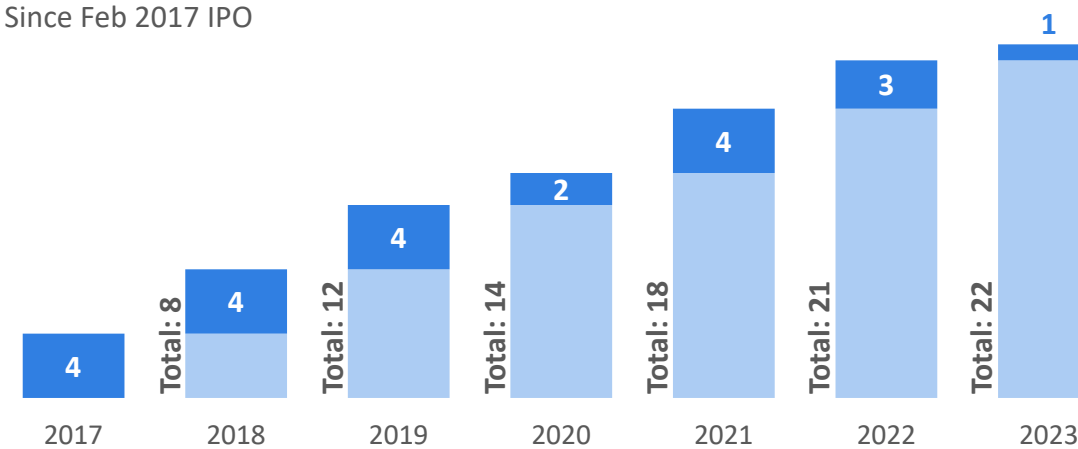
Owned Midstream (Miles) 17,700

Hedge strategy reduces sensitivity to commodity price volatility



Acquisitions per Year

Since Feb 2017 IPO



Market data sourced from Bloomberg and using GBP:USD exchange rate of 1:0.8313; Volumetric conversion assume Boe:Mcf conversion rate of 1:6

For Company-specific terms or Non-IFRS measures, please refer to the "Glossary of Terms", "Alternative Performance Metrics" and "Non-IFRS Reconciliations" within the Company's 2022 Annual Report

a) As published within the Company's 2022 Annual Report

b) Measured as current Net Debt, divided by pro forma Adjusted EBITDA for the twelve months ended 31 March 2023, adjusted for the annualised impact of the previously announced East Texas, ConocoPhillips and Tanos II acquisitions.

c) Calculated as the value of the Company's reserves at 31 December 2022, adjusted for the pro forma impact of the previously announced Tanos II acquisition



2022 ESG and Sustainability Highlights

- ✓ **Achieved OGMP 2.0 "Gold Standard" for Emissions Reporting**
1 of 5 US operators to receive designation in 2022
- ✓ **Conducted ~174,000 Handheld Inspections for Fugitive Emissions**
Completed two or more inspections on 95% of producing wellsites in Appalachia
- ✓ **11,000 Miles of Midstream Pipelines Surveyed via Aerial Lidar**
65% of Appalachia assets surveyed, Includes ~10,500 wells and facilities
- ✓ **More Than 500% Increase on Near Miss/ Good Catch Reporting**
OneDEC safety culture expands awareness, reporting and training programs
- ✓ **Top 3 in Energy Sector of FTSE250 - Women's Review Performance Report**

2023 Emissions Reduction Initiatives

Central Region Handheld Deployment

Conduct emissions surveys on 100% of upstream assets

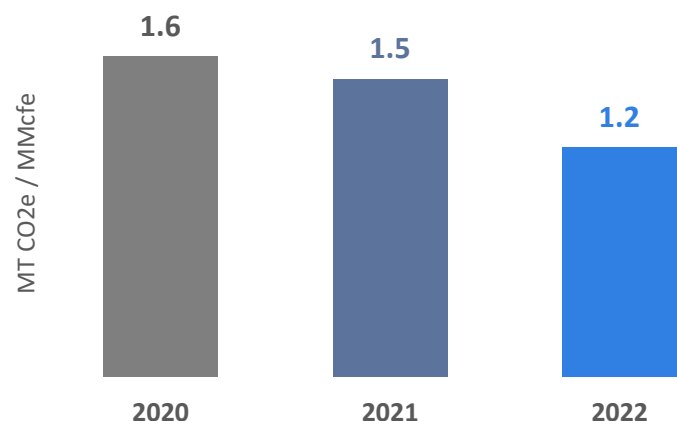
Ongoing Pneumatic Device Replacement

Convert existing devices to compressed air / solar

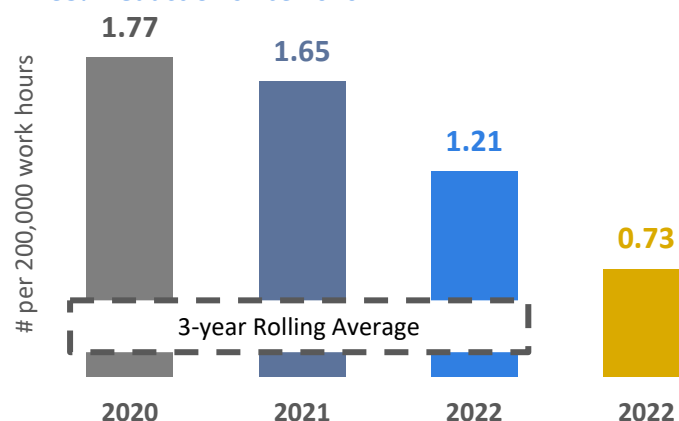
Continuation of Aerial LiDAR Surveys

Progress midstream emissions surveillance in Appalachia

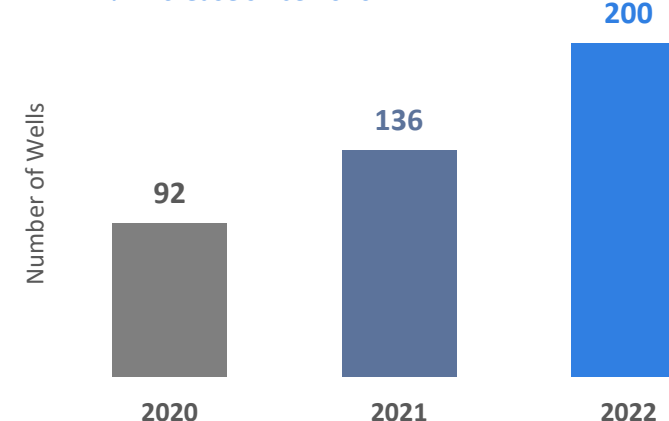
Scope 1 Methane Emissions Intensity
25% reduction since 2020



Total Recordable Incident Rate
35% reduction since 2020



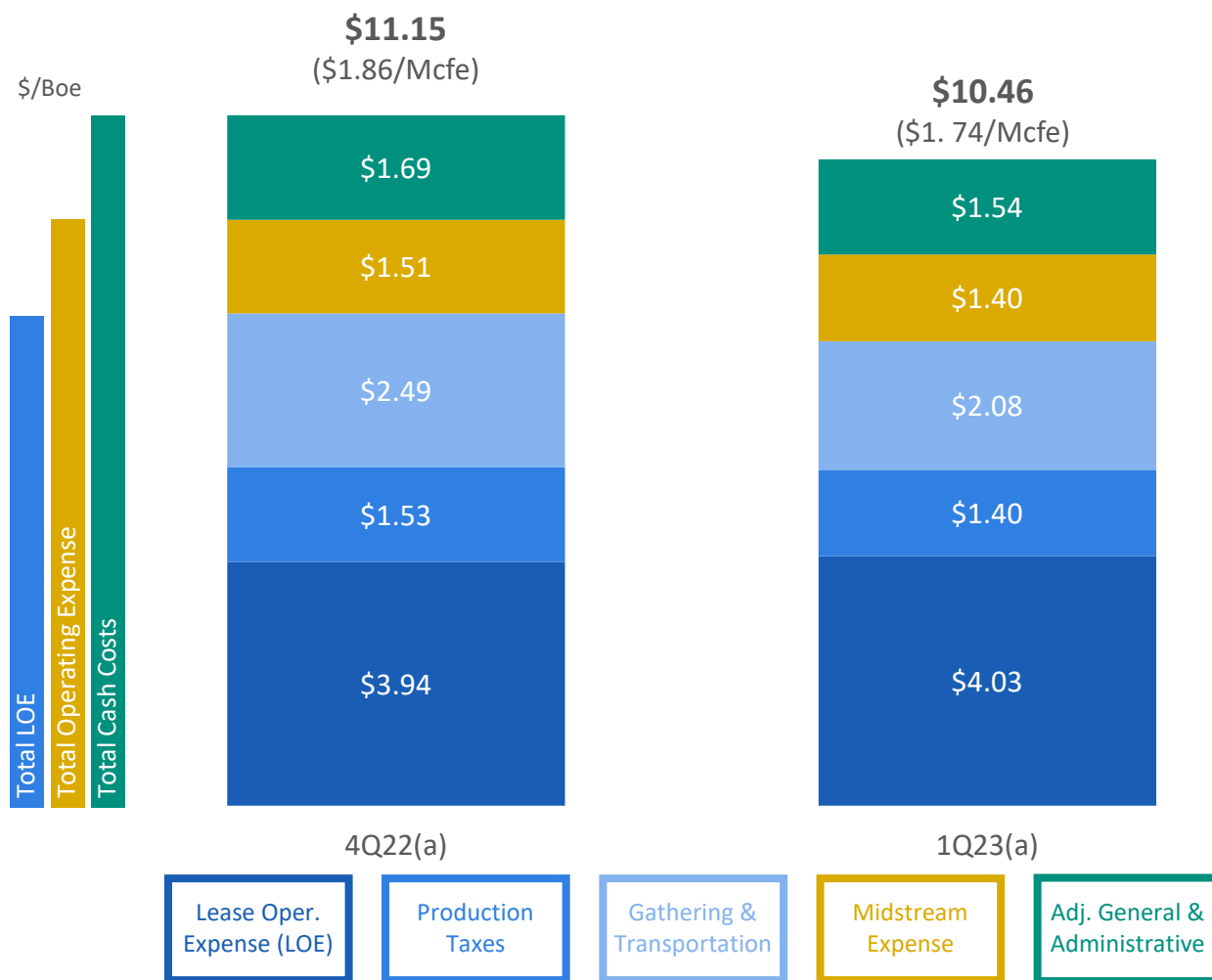
Wells Retired per Year^(a)
117% increase since 2020



a) For comparative purposes, 2022 excludes 14 wells retired in 2022 within Diversified's Central Region



HISTORICAL OPERATING EXPENSES BY NATURE



Expanding Margins on Decreased Costs

6% decrease in Total Cash Costs per unit drives margin improvement over sequential quarters

Vertically Integrated for Cost Insulation

Integrated marketing, midstream and asset retirement limit inflationary cost pressure

Strategically “Hedging” Variable Costs

Diversification of operating regions increases durability of margins throughout the price cycle

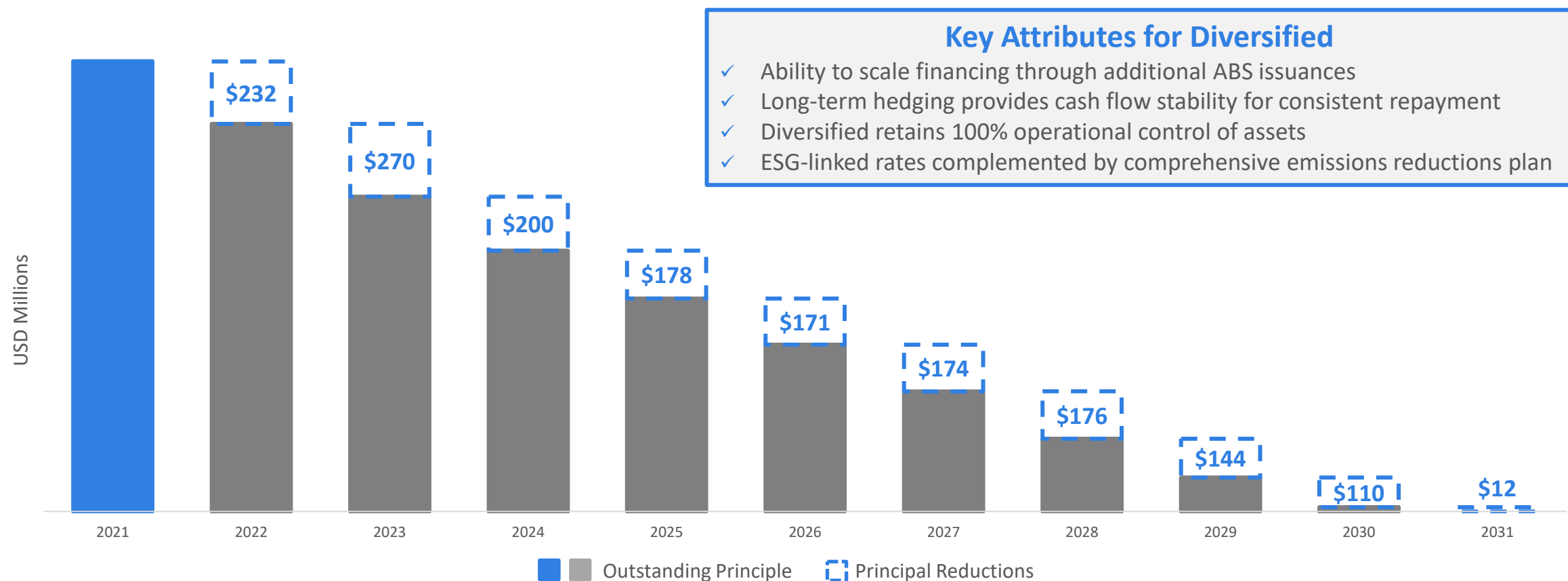
For Company-specific terms or Non-IFRS measures, please refer to the “Glossary of Terms”, “Alternative Performance Metrics” and “Non-IFRS Reconciliations” within the Company’s 2022 Annual Report

a) 4Q22 excludes \$0.28/Boe (\$0.05/Mcfe) of revenue and \$(0.34)/Boe \$(0.06)/Mcfe) of expenses attributable to Next LVL Energy; 1Q23 excludes \$0.35/Boe (\$0.06/Mcfe) of revenue and \$(0.28)/Boe \$(0.05)/Mcfe) of expenses attributable to Next LVL Energy

b) Certain gathering and transportation contracts in the Central Region include fee components linked to prevailing commodity prices



AMORTISING DEBT STRUCTURES DRIVE DISCIPLINED REPAYMENT



Naturally aligned with Diversified's long-life, low decline production

Scheduled for full repayment 8-10 years before legal maturity

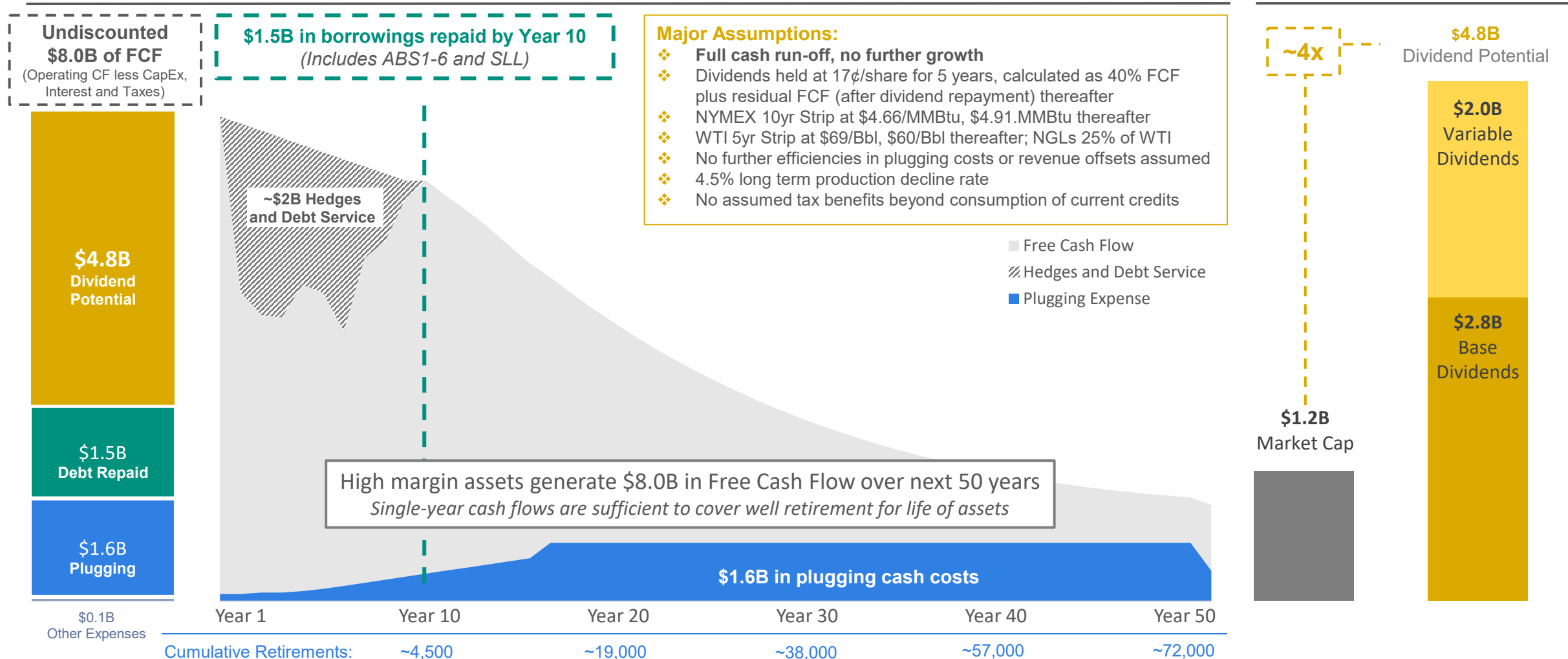
Creates clear line-of-sight to uses of cash and capacity for deleveraging

Illustrative schedule of amortising payments relates to Diversified's long-term securitised instruments, inclusive of ABS structures announced through 27 October 2022 and secured term loan; actual payment amounts per year may differ from the above due to 25% excess amortization requirement for ABS I; For more information regarding Diversified's total borrowings, please refer to the Company's 2022 Annual Report



ILLUSTRATIVE: 50 YEAR COMPLETE PORTFOLIO RETIREMENT SCENARIO

\$8.0 billion in Free Cash Flows provide ~\$4.8 billion in dividend potential while also repaying all debt outstanding and generating sufficient Free Cash Flows to retire all wells without the use of a sinking fund

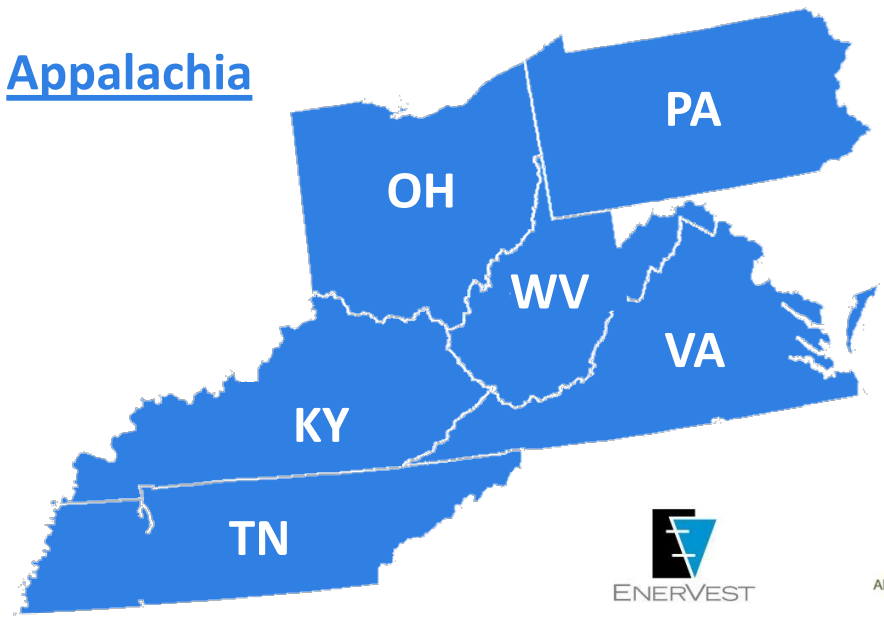


PDP Roll-off major assumptions: 10-year natural gas strip pricing at average of \$4.66/MMBtu with prices held flat thereafter at \$4.91; Differentials assumption of \$(0.55)/MMBtu; 5yr oil strip pricing at \$69/Bbl and \$60/Bbl thereafter; NGL pricing assumes realisations at 25% of WTI; 5% production terminal decline rate; Hedge Portfolio as of 26 October 2022; Dividends held flat at 17¢ per share for 5 years and then 40% of Free Cash Flows, plus all residual cash flows after debt repayment ("Variable Dividend"); Variable LOE expenses declining with production; fixed LOE/well declining as wells are plugged; G&A linked to both production declines and well count declines; midstream revenue and expense declining 3% annually; production taxes 4% of revenue; no cash tax benefits included; capital expenditures declining with production

DRIVING VALUE THROUGH ACCRETIVE ACQUISITIONS

Apply industry leading Smart Asset Management (SAM) on larger PDP base without balance sheet stress

Appalachia



Central



~\$2.7 Billion
22 acquisitions since
2017 IPO



Total acquisition count reflective of announced acquisitions since February 2017 IPO and not inclusive of acquired asset retirement companies and equipment



ENHANCING OPERATING SCALE AND EFFICIENCIES THROUGH ACQUISITIONS

\$322 Million

of Complementary Acquisitions in 2022

\$566 Million

Including Tanos Energy II (2023)

East Texas Bolt-On

Allocate value to PDP assets with embedded upside potential

\$35_{MM}

Estimated Adj. EBITDA^(a)

>PV40

Equivalent Purchase Price^(b)

1.4x

Purchase Price Multiple^(c)

ConocoPhillips

Proximity to existing assets builds line-of-sight to future synergies

\$82_{MM}

Estimated Adj. EBITDA^(a)

~PV17

Equivalent Purchase Price^(b)

~2.5x

Purchase Price Multiple^(c)

Midstream Systems

Enhance control of product flow and regional cash margins

95%

Equity Volumes Transported

80%

Transport Capacity Remaining

2.4x

Purchase Price Multiple^(c)

Asset Retirement

Reduce third party reliance and provide long-term cost control

12

Retirement Rigs Added

~350

Annual Well Retirement Capacity^(d)

150+

External Retirement Contracts in 2023

Source: Company Data

a) Estimated Adjusted EBITDA reflects the previously announced next twelve months adjusted EBITDA from anticipated and respective close dates of acquisitions and assumes NYMEX pricing as commensurate with acquisition evaluation and announcement date; amounts not reflective of synergies that may be realised following post-acquisition integration

b) PV-10 values as previously announced and reflective of the NYMEX strip pricing commensurate with acquisition evaluation and announcement date as applicable for effective date of PDP reserves

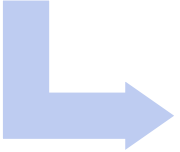
c) Calculated as estimated net purchase price divided by estimated NTM Adjusted EBITDA; net purchase price assumes estimated and customary purchase price adjustments

d) Annual well-retirement capacity calculated as 30 wells plugged per year, per crew, and includes wells plugged for Diversified, state regulators and other operators; Actual amounts may vary due to nature and timing of wells plugged

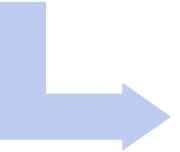


GROWTH VIA ACQUISITION WITH LOW-RISK UPSIDE

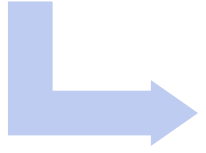
Utilise **track record** of underwriting, buying and managing undervalued assets as a competitive advantage



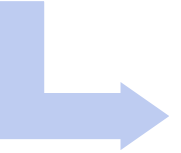
Leverage **long-standing relationships** with advisors, investment banks and lenders to source unique opportunities



Remain disciplined in acquiring assets at **accretive multiples**



Underwrite and analyze PDP and upside potential, but focus on producing **predictable cash flow**



Optimise assets post transaction by lowering cost structure workovers and targeted capital spending

Market Volatility & Dislocation = Opportunity Set
More economic to buy reserves which yields low capital expenses, ability to return cash to shareholders and ample cash flows for reinvestment

Results
Created significant, low decline production with substantial inventory of capital efficient **redevelopment opportunities** across a core asset base that allows for synergies from both personnel and skillsets



COMMODITY DERIVATIVES PORTFOLIO (AS OF 01 MAY 2023)

Natural Gas Annual Summary^(a)

2023

\$3.79/Mcf
~85% Hedged

2024

\$3.30/Mcf
~80% Hedged

2025

\$3.23/Mcf
~70% Hedged

Natural Gas Financial Derivatives Contracts

Natural Gas (MMBtu, \$/MMBtu)		1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24	FY23	FY24	FY25	FY26
NYMEX NG Swaps ^(b)	Volume	53,638,196	57,669,356	55,529,183	52,357,660	50,733,461	51,516,162	50,366,559	47,499,467	219,194,395	200,115,649	162,295,266	109,096,676
	Swap Price	\$3.56	\$3.57	\$3.50	\$3.54	\$3.06	\$3.10	\$3.09	\$3.04	\$3.54	\$3.07	\$3.02	\$2.94
NYMEX NG Costless Collars	Volume	1,038,000	130,400	119,600	1,257,700	2,559,500	-	-	-	2,545,700	2,559,500	-	-
	Ceiling	\$10.67	\$3.90	\$3.90	\$6.28	\$5.84	\$0.00	\$0.00	\$0.00	\$7.84	\$5.84	\$0.00	\$0.00
	Floor	\$6.10	\$3.05	\$3.05	\$3.96	\$3.77	\$0.00	\$0.00	\$0.00	\$4.60	\$3.77	\$0.00	\$0.00
NYMEX NG Costless Collars	Volume	3,600,000	-	-	-	-	-	-	-	3,600,000	-	-	-
	Ceiling	\$3.37	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$3.37	\$0.00	\$0.00	\$0.00
	Floor	\$2.63	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.63	\$0.00	\$0.00	\$0.00
	Sub-Floor	\$2.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$2.00	\$0.00	\$0.00	\$0.00
Consolidated NYMEX Hedges	Volume	58,276,196	57,799,756	55,648,783	53,615,360	53,292,961	51,516,162	50,366,559	47,499,467	225,340,095	202,675,149	162,295,266	109,096,676
	Wtd Average Price	\$3.54	\$3.57	\$3.49	\$3.55	\$3.09	\$3.10	\$3.09	\$3.04	\$3.54	\$3.08	\$3.02	\$2.94

Natural Gas (MMBtu, \$/MMBtu)		FY27	FY28	FY29	FY30
NYMEX NG Swaps ^(a)	Volume	90,412,486	32,190,000	29,190,000	5,450,000
	Wtd Average Price	\$3.00	\$1.97	\$1.97	\$1.90
NYMEX NG Costless Collars	Volume	1,414,243	5,382,462	3,726,485	-
	Ceiling	\$6.70	\$6.45	\$7.02	\$0.00
	Floor	\$4.00	\$4.00	\$4.00	\$0.00
NYMEX NG Puts	Volume	-	22,618,008	-	-
	Floor	\$0.00	\$3.00	\$0.00	\$0.00
NYMEX NG Put Spread	Volume	4,906,152	31,585,108	30,066,401	14,491,673
	Floor	\$2.10	\$2.73	\$2.73	\$2.74
	Sub-Floor	\$1.80	\$1.80	\$1.80	\$1.80
Consolidated NYMEX Hedges	Volume	96,732,881	91,775,578	62,982,886	19,941,673
	Wtd Average Price	\$2.97	\$2.61	\$2.45	\$2.51

Natural Gas Basis (MMBtu, \$/MMBtu)		1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24	FY23	FY24	FY25	FY26
Consolidated Basis Hedges	Volume	35,724,718	51,885,387	52,167,251	51,376,441	32,489,003	31,061,570	30,681,191	27,051,802	191,153,796	121,283,566	-	-
	Wtd Average Price	(\$0.59)	(\$0.62)	(\$0.62)	(\$0.62)	(\$0.71)	(\$0.73)	(\$0.74)	(\$0.77)	(\$0.61)	(\$0.73)	(\$0.00)	\$0.00

a) Illustrative percent of production hedged calculated using the company's published derivatives portfolio and illustrative production volume, calculated using reported production and declines pro forma for the impact of the previously announced Tanos II acquisition; Corporate Btu factor of 1.07 should be used when converting Natural Gas pricing from MMBtu to Mcf.

b) Excludes sold calls on 56,000 MMBtu/d in 2023 at a weighted average price of \$2.75/MMBtu, and 60,000 MMBtu/d at a weighted average price of \$4.00/MMBtu in 2026; Prices above exclude the impact of the cash settlement of deferred premiums from previous hedge optimisations, which include expected payments on settled derivative instruments of ~\$43 million in 2023, ~\$50 million in 2024 and ~\$35 million in 2025



COMMODITY DERIVATIVES PORTFOLIO (AS OF 01 MAY 2023)

NGLs

Annual Summary^(a)

2023

\$37.37/bbl
~ 70% Hedged

2024

\$38.25/bbl
~ 50% Hedged

2025

\$30.22/bbl
~35% Hedged

Oil

Annual Summary^(a)

2023

\$69.31/bbl
~ 70% Hedged

2024

\$62.54/bbl
~ 40% Hedged

2025

\$59.01/bbl
~35% Hedged

Natural Gas Physical Contracts

Natural Gas + Basis (MMBtu, \$/MMBtu)		1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24	FY23	FY24	FY25	FY26
NYMEX Contracts	Volume	3,600,000	1,820,000	1,840,000	1,840,000	-	-	-	-	9,100,000	-	-	-
	Fixed Price	\$7.85	\$4.40	\$4.40	\$4.40	\$0.00	\$0.00	\$0.00	\$0.00	\$5.76	\$0.00	\$0.00	\$0.00
All-In Physical Contracts	Volume	-	-	-	-	-	-	-	-	-	-	-	-
	Fixed Price	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Consolidated Basis Contracts	Volume	9,770,000	1,820,000	1,840,000	1,840,000	-	-	-	-	15,270,000	-	-	-
	Wtd Average Price	(\$0.71)	(\$1.11)	(\$1.11)	(\$1.11)	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.85)	\$0.00	\$0.00	\$0.00

Natural Gas Liquids Financial Derivatives Contracts

NGL (bbl, \$/bbl)		1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24	FY23	FY24	FY25	FY26
Consolidated NGL Hedges ^(b)	Volume	1,167,196	1,201,456	1,190,318	1,171,275	771,245	757,091	745,198	732,417	4,730,246	3,005,952	1,860,617	1,058,120
	Wtd Average Price	\$37.30	\$37.35	\$37.40	\$37.43	\$38.21	\$38.23	\$38.26	\$38.29	\$37.37	\$38.25	\$30.22	\$27.66

Oil Financial Derivatives Contracts

Oil (bbl, \$/bbl)		1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24	FY23	FY24	FY25	FY26
Consolidated WTI Hedges ^(c)	Volume	250,711	240,981	229,172	218,991	115,334	110,101	105,441	100,105	939,855	430,981	365,644	282,770
	Wtd Average Price	\$69.61	\$69.37	\$69.19	\$69.04	\$62.62	\$62.50	\$62.41	\$62.62	\$69.31	\$62.54	\$59.01	\$59.48

a) Illustrative percent of production hedged calculated using the company's published derivatives portfolio and illustrative production volume, calculated using reported production and declines pro forma for the impact of the previously announced Tanos II acquisition;

b) Excludes sold calls of ~1,000 bbl/d at \$24.78/bbl in 2023 and ~2,500 bbl/d at \$31.29/bbl in 2024

c) Excludes sold calls of ~320 bbl/d at \$53.20 in 2023 and ~500 bbl/d at \$70.00/bbl in 2024

Natural Gas Macro



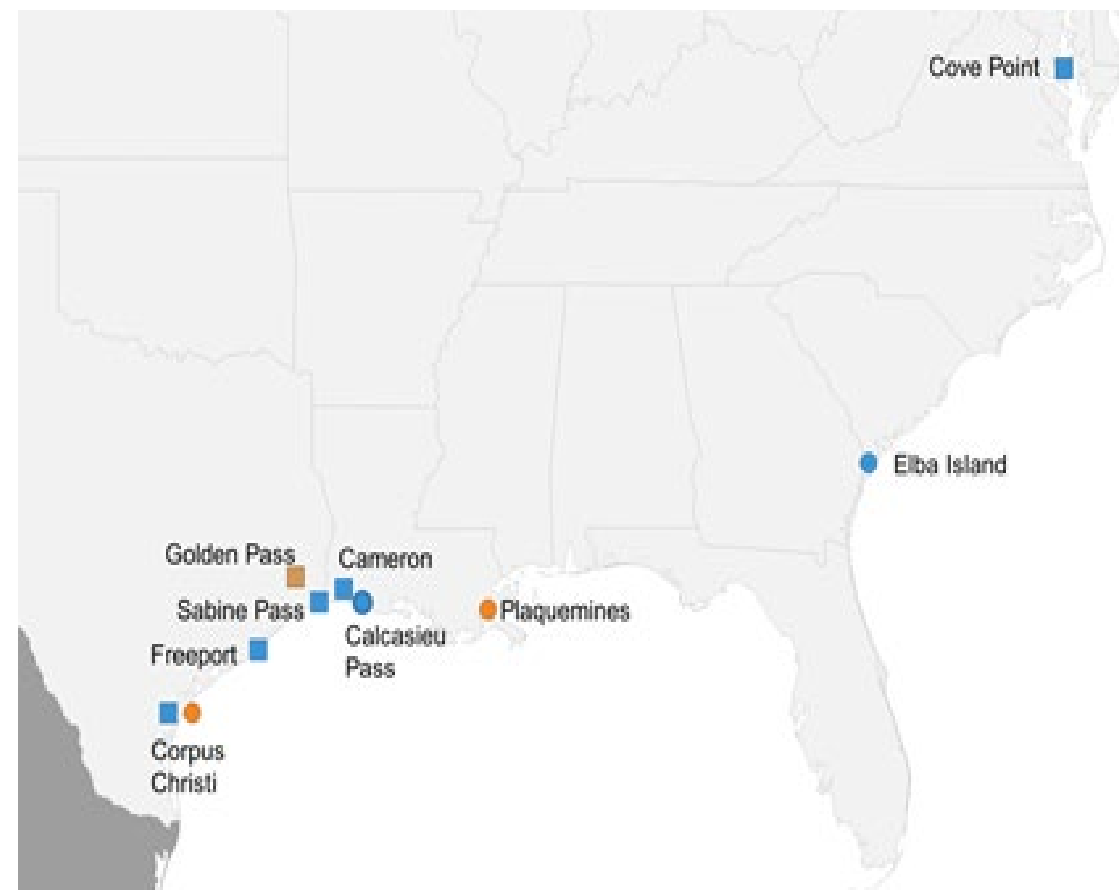
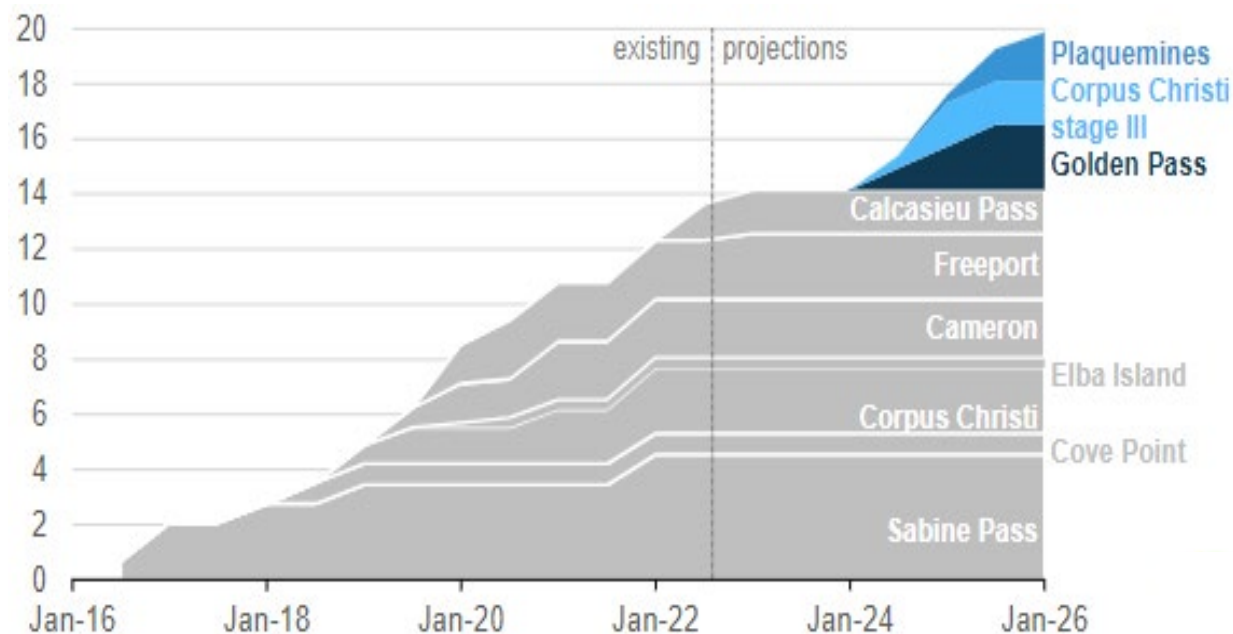
GROWING NATURAL GAS EXPORT CAPACITY

Clean U.S. natural gas provides energy security to other nations and allows for a global reduction of emissions

U.S. LNG Projects Under Construction

Once completed, the three highlighted export projects will add **~6 billion** cubic feet of export capacity by 2025

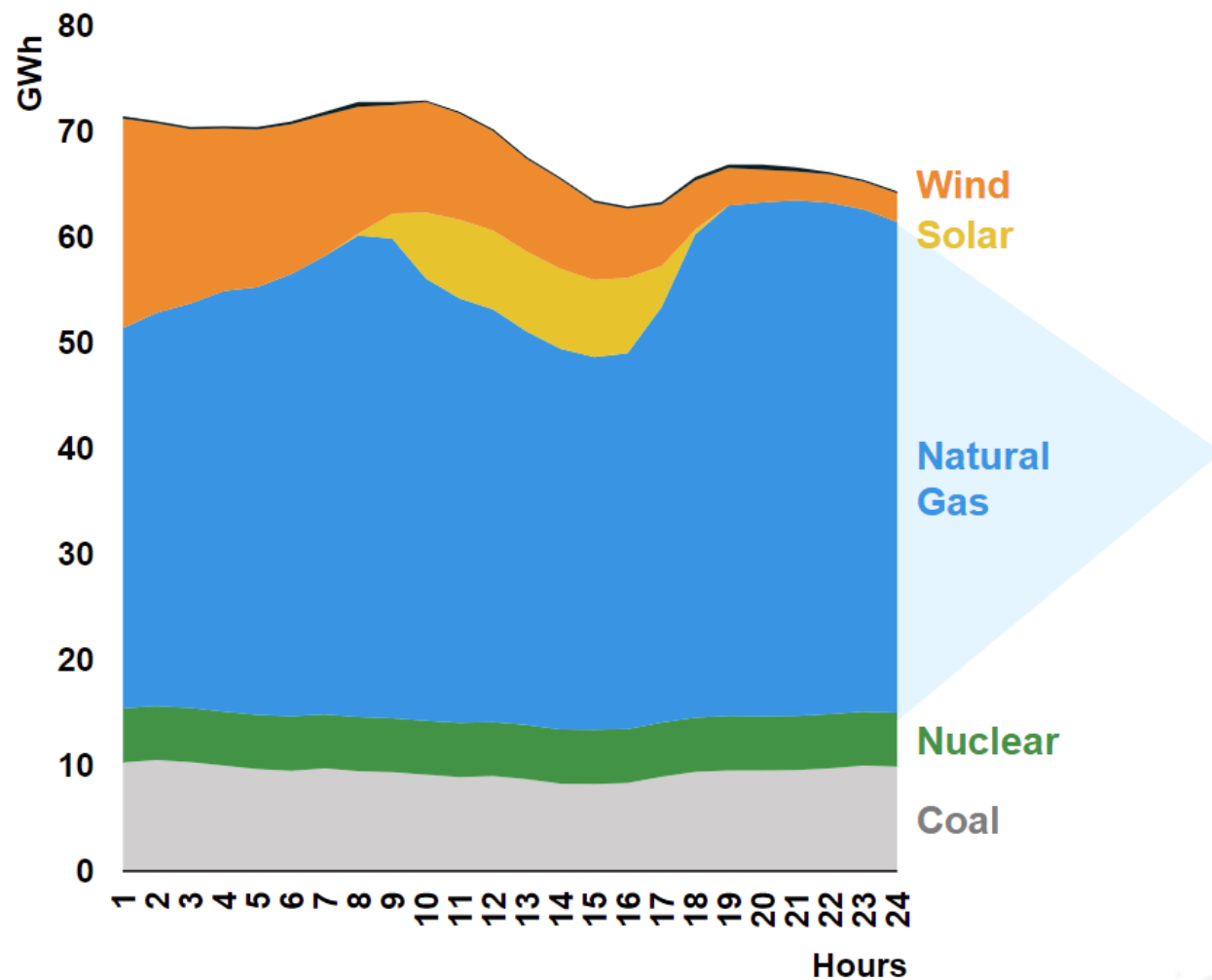
Capacity could double to **~30 billion** cubic feet by 2030





RENEWABLES BUILDOUT REQUIRES NATURAL GAS BACKSTOP

Texas Hourly Power Generation *(December 23, 2022)*



RELIABILITY OF BASE LOAD

Natural Gas supported peak demand needs in Texas during Winter Storm Elliot

Stepped up to fill **~70%** of demand during hours when the sun wasn't shining & wind power collapsed

Dispatchable capacity need for low wind and solar days

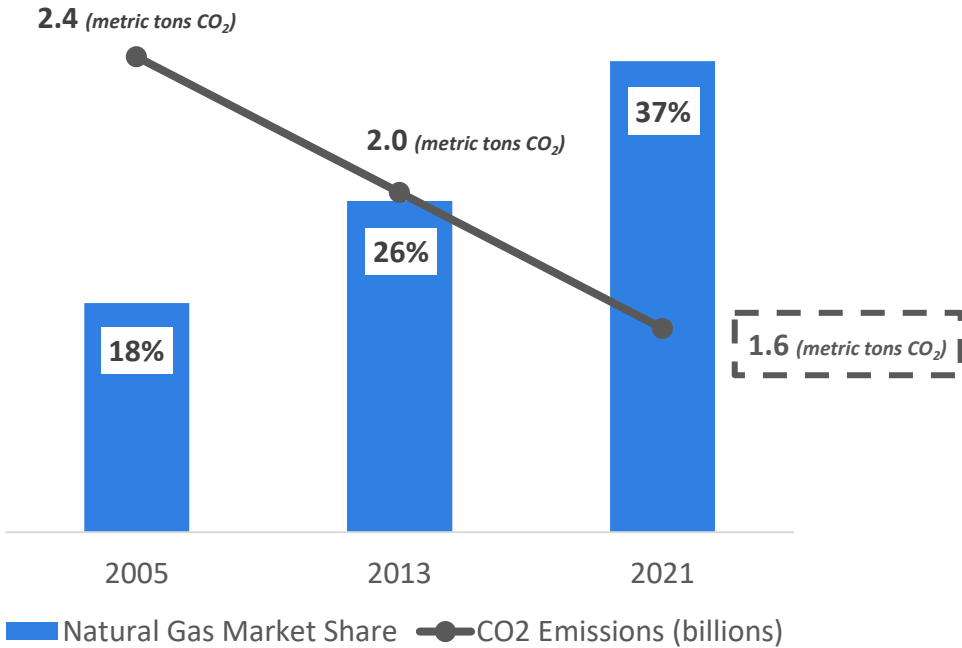


INCREASED NATURAL GAS USAGE DRIVES LOWER EMISSIONS

U.S. CO₂ emissions declined ~35% with increased natural gas power generation

U.S. Electric Power Generation

CO₂ Emissions vs. Natural Gas Market Share



Coal to Natural Gas Switching



Natural gas generation increased from 18% to 37% of the total power market



Shift to natural gas directly responsible for reducing CO₂ power emissions



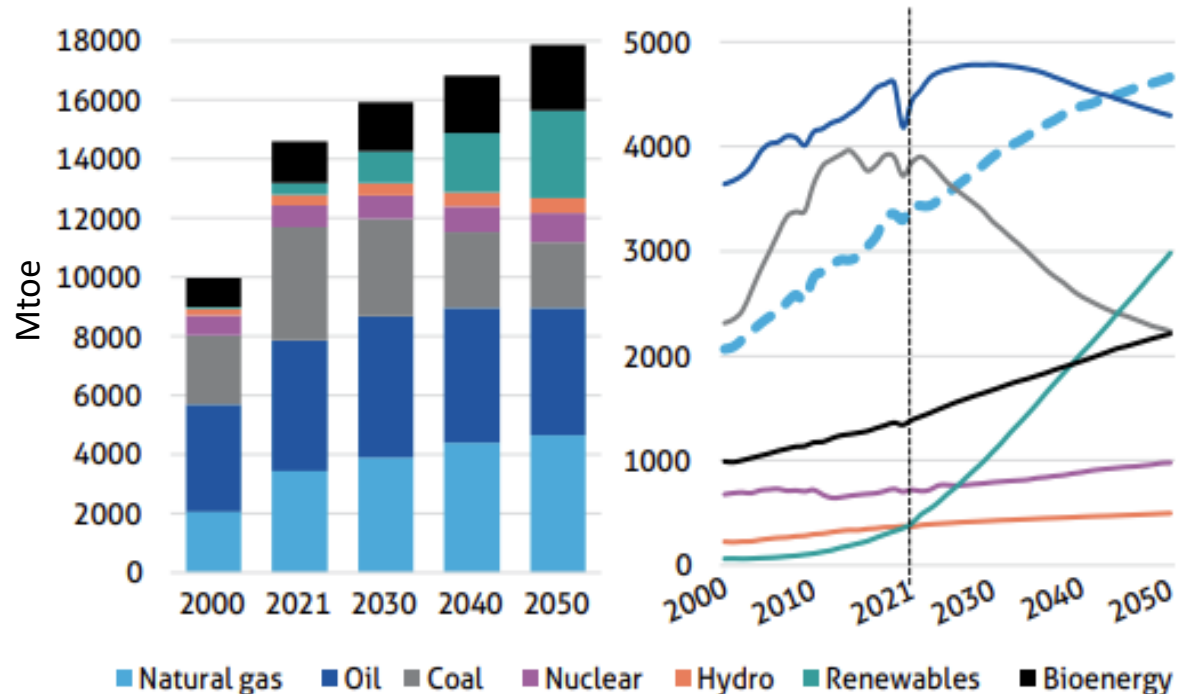
There are still ~230 operating coal plants in the U.S. today



MEANINGFUL GLOBAL ENERGY DEMAND FROM FOSSIL FUELS

Natural Gas will be the most utilized fuel by 2043 and be a 26% share of energy demand in 2050

Global Primary Energy Power Demand Trends by Fuel Type



Global natural gas demand to increase by 36%

Driven by electricity demand, clean air policies, and coal/oil to gas switching

Asia Pacific demand to increase by 78%

Fast-growing economies in China and India provide the largest growth engine

Fossil fuels forecast to be 63% of market in 2050

Despite energy transition and the rapid contribution of renewables

Natural gas overtakes coal in 2025

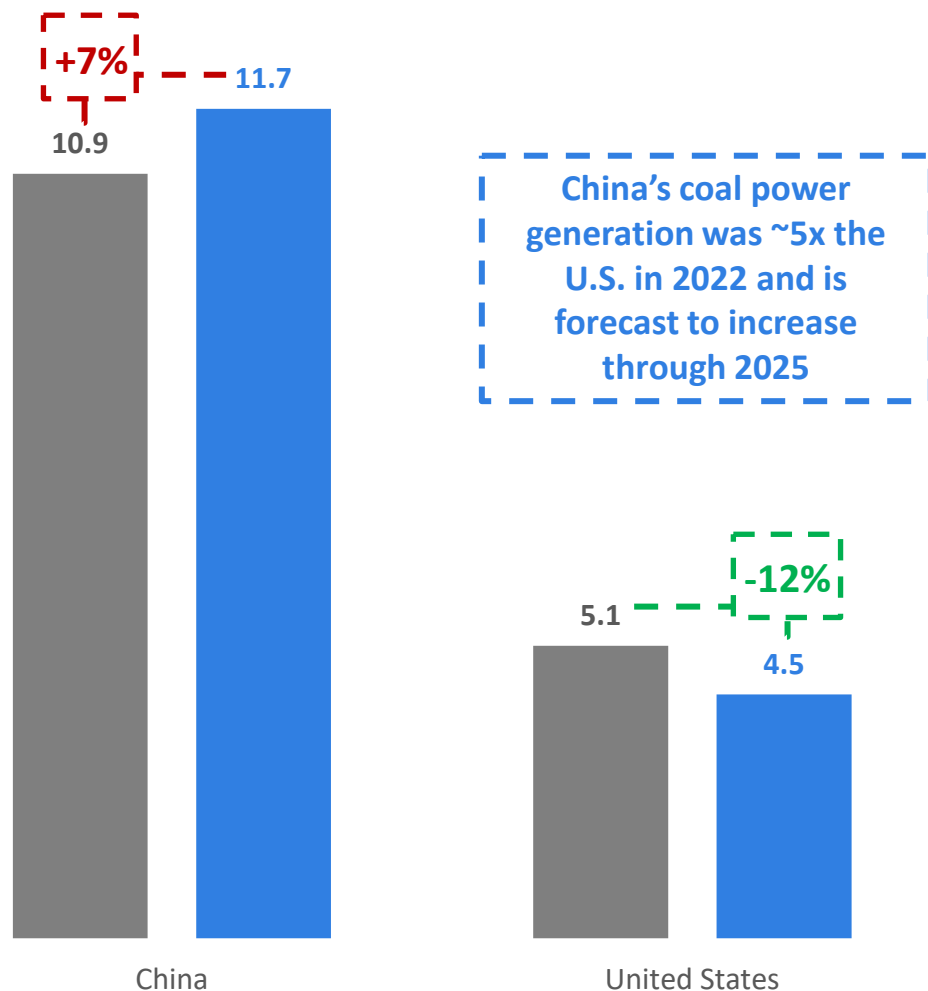
Industrial natural gas demand will rise as a feedstock for the production of petrochemicals and fertilizers



WE SHARE A COMMON ENVIRONMENT

2020 CO₂ Emissions (Gt)

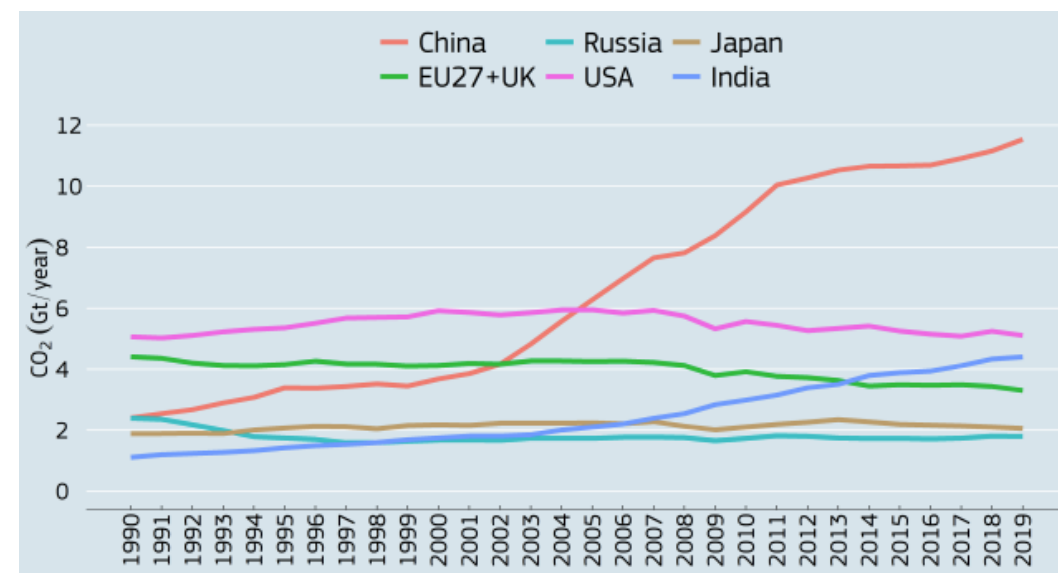
■ 2017 ■ 2020



Need to address International Emissions:

- China's emissions have grown meaningfully since 1990 including 7% since 2017
- U.S. represents only 18% of the five top emitting counties/regions
- U.S. has reduced emissions 12% since 2017

Fossil CO₂ Emissions from Major Economies



Supplemental Information

For the Year Ended 31 December 2022



AUDITED FINANCIAL STATEMENTS *(FOR THE YEAR ENDED 31 DECEMBER 2022)*

CONSOLIDATED STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

	Year-Ended	
	31 December 2022	31 December 2021
Revenue	\$ 1,919,349	\$ 1,007,561
Operating expense	(445,893)	(291,213)
Depreciation, depletion and amortization	(222,257)	(167,644)
Gross profit	1,251,199	548,704
General and administrative expense	(170,735)	(102,326)
Allowance for expected credit losses	-	4,265
Gain (loss) on natural gas and oil property and equipment	2,379	(901)
Gain (loss) on derivative financial instruments	(1,758,693)	(974,878)
Gains on bargain purchases	4,447	58,072
Operating profit (loss)	(671,403)	(467,064)
Finance costs	(100,799)	(50,628)
Accretion of asset retirement obligation	(27,569)	(24,396)
Loss on joint interest owner receivable	-	-
Loss on debt cancellation	-	-
Other income (expense)	269	(8,812)
Income (loss) before taxation	(799,502)	(550,900)
Income tax benefit (expense)	178,904	225,694
Net income (loss)	(620,598)	(325,206)
Other comprehensive income (loss)	940	51
Total comprehensive income (loss)	\$ (619,658)	\$ (325,155)
Net income (loss) attributable to:		
Diversified Energy Company PLC	\$ (625,410)	\$ (325,509)
Non-controlling interest	4,812	303
Net income (loss)	\$ (620,598)	\$ (325,206)
Weighted average shares outstanding - basic and diluted	844,080	793,542
Earnings (loss) per share - basic and diluted	\$ (0.74)	\$ (0.41)



AUDITED FINANCIAL STATEMENTS *(FOR THE YEAR ENDED 31 DECEMBER 2022)*

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	31 December 2022	31 December 2021
ASSETS		
Non-current assets:		
Natural gas and oil properties, net	\$ 2,555,808	\$ 2,530,078
Property, plant and equipment, net	462,860	413,980
Intangible assets	21,098	14,134
Restricted cash	47,497	18,069
Derivative financial instruments	13,936	219
Deferred tax asset	371,156	176,955
Other non-current assets	4,351	3,635
Total non-current assets	\$ 3,476,706	\$ 3,157,070
Current assets:		
Trade receivables, net	296,781	282,922
Cash and cash equivalents	7,329	12,558
Restricted cash	7,891	1,033
Derivative financial instruments	27,739	1,052
Other current assets	14,482	39,574
Total current assets	354,222	337,139
Total assets	\$ 3,830,928	\$ 3,494,209

	31 December 2022	31 December 2021
EQUITY AND LIABILITIES		
Shareholders' equity:		
Share capital	\$ 11,503	\$ 11,571
Share premium	1,052,959	1,052,959
Treasury reserve	(100,828)	(68,537)
Share based payment and other reserves	17,650	14,156
Retained earnings (accumulated deficit)	(1,133,972)	(362,740)
Non-controlling interest	14,964	16,541
Total equity	\$ (137,724)	\$ 663,950
Non-current liabilities:		
Asset retirement obligations	452,554	522,190
Leases	19,569	18,177
Borrowings	1,169,233	951,535
Deferred tax liability	12,490	-
Derivative financial instruments	1,177,801	556,982
Other non-current liabilities	5,375	7,775
Total non-current liabilities	2,837,022	2,056,659
Current liabilities:		
Trade and other payables	93,764	62,418
Leases	9,293	9,627
Borrowings	271,096	58,820
Derivative financial instruments	293,840	251,687
Other current liabilities	463,637	391,048
Total current liabilities	1,131,630	773,600
Total liabilities	3,968,652	2,830,259
Total equity and liabilities	\$ 3,830,928	\$ 3,494,209



AUDITED FINANCIAL STATEMENTS *(FOR THE YEAR ENDED 31 DECEMBER 2022)*

CONSOLIDATED STATEMENTS OF CASH FLOW

	Year Ended	
	31 December 2022	31 December 2021
Cash flows from operating activities:		
Income (loss) after taxation	\$ (620,598)	\$ (325,206)
Cash flows from operations reconciliation:		
Depreciation, depletion and amortisation	222,257	167,644
Accretion of asset retirement obligations	27,569	24,396
Income tax (benefit) expense	(178,904)	(225,694)
(Gain) loss on fair value adjustments of unsettled financial instruments	861,457	652,465
Asset retirement costs	(4,889)	(2,879)
(Gain) loss on natural gas and oil properties and equipment	(2,379)	901
Gain on bargain purchases	(4,447)	(58,072)
Finance costs	100,799	50,628
Revaluation of contingent consideration	-	8,963
Loss on early retirement of debt	-	-
Loss on joint interest owner receivable	-	-
Hedge modifications	(133,573)	(10,164)
Non-cash equity compensation	8,051	7,400
Working capital adjustments:	-	-
Change in trade receivables and other current assets	13,760	(126,957)
Change in other current assets	25,440	(4,233)
Change in other non-current assets	(580)	(556)
Change in trade and other payables and other current liabilities	132,349	162,486
Change in other non-current liabilities	(6,794)	5,707
Cash generated from operations	414,078	331,062
Cash paid for income taxes	(26,314)	(10,880)
Net cash provided by operating activities	\$ 387,764	\$ 320,182

	Year Ended	
	31 December 2022	31 December 2021
Cash flows from investing activities:		
Consideration for business acquisitions, net of cash acquired	\$ (24,088)	\$ (286,804)
Consideration for asset acquisitions	(264,672)	(287,330)
Proceeds from divestitures	-	86,224
Payments associated with potential acquisitions	-	(25,002)
Acquisition related debt and hedge extinguishments	-	(56,466)
Expenditures on natural gas and oil properties and equipment	(86,079)	(50,175)
Proceeds on disposals of natural gas and oil properties and equipment	12,189	2,663
Other acquired intangibles	-	-
Contingent consideration payments	(23,807)	(10,822)
Net cash used in investing activities	(386,457)	(627,712)
Cash flows from financing activities:		
Repayment of borrowings	(2,148,986)	(1,432,566)
Proceeds from borrowings	2,596,854	1,727,745
Cash paid for interest	(82,936)	(41,623)
Debt issuance cost	(34,234)	(10,255)
(Increase) decrease in restricted cash	(36,287)	1,838
Hedge modifications associated with ABS Notes	(105,316)	-
Proceeds from equity issuance, net	-	213,844
Principal element of lease payments	(11,233)	(8,606)
Cancellation (settlement) of warrants, net	137	(1,429)
Dividends to shareholders	(143,455)	(130,239)
Distributions to non-controlling interest owners	(6,389)	-
Issuance of shares from the EBT	-	-
Repurchase of shares by the EBT	(22,931)	-
Repurchase of shares	(11,760)	-
Net cash provided by financing activities	(6,536)	318,709
Net change in cash and cash equivalents	(5,229)	11,179
Cash and cash equivalents, beginning of period	12,558	1,379
Cash and cash equivalents, end of period	\$ 7,329	\$ 12,558



ALTERNATIVE PERFORMANCE METRICS (FOR THE YEAR ENDED 31 DECEMBER 2022)(UNAUDITED)

Adjusted EBITDA and Adjusted EBITDA per Share

As used herein, EBITDA represents earnings before interest, taxes, depletion, depreciation and amortisation. Adjusted EBITDA includes adjusting for items that are not comparable period-over-period, namely, accretion of asset retirement obligation, other (income) expense, loss on joint and working interest owners receivable, (gain) loss on bargain purchases, (gain) loss on fair value adjustments of unsettled financial instruments, (gain) loss on natural gas and oil property and equipment, costs associated with acquisitions, other adjusting costs, non-cash equity compensation, (gain) loss on foreign currency hedge, net (gain) loss on interest rate swaps and items of a similar nature.

Adjusted EBITDA should not be considered in isolation or as a substitute for operating profit or loss, net income or loss, or cash flows provided by operating, investing and financing activities. However, we believe such measure is useful to an investor in evaluating our financial performance because it (1) is widely used by investors in the natural gas and oil industry as an indicator of underlying business performance; (2) helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the often-volatile revenue impact of changes in the fair value of derivative instruments prior to settlement; (3) is used in the calculation of a key metric in one of our Credit Facility financial covenants; and (4) is used by us as a performance measure in determining executive compensation. When evaluating this measure, we believe investors also commonly find it useful to evaluate this metric as a percentage of our Total Revenue, Inclusive of Hedges, producing what we refer to as our Adjusted EBITDA Margin.

We believe that Adjusted EBITDA per Share provides direct line of sight into our ability to measure the accretive growth we seek to acquire while providing shareholders with a depiction of cash earnings at the share level. In this calculation we utilise weighted average shares as to not disproportionately weight the calculation for equity issued for acquisitive growth at varying periods throughout the year.

	Year Ended	
	31 December 2022	31 December 2021
Net income (loss)	\$ (620,598)	\$ (325,206)
Finance costs	100,799	50,628
Accretion of asset retirement obligations	27,569	24,396
Other (income) expense	(269)	8,812
Income tax (benefit) expense	(178,904)	(225,694)
Depreciation, depletion and amortisation	222,257	167,644
Loss on joint and working interest owners receivable	-	-
(Gain) loss on bargain purchases	(4,447)	(58,072)
(Gain) loss on fair value adjustments of unsettled financial instruments	861,457	652,465
(Gain) loss on natural gas and oil property and equipment(a)	93	901
Costs associated with acquisitions	15,545	27,743
Other adjusting costs	69,967	10,371
Non-cash equity compensation	8,051	7,400
(Gain) loss on foreign currency hedge	-	1,227
(Gain) loss on interest rate swap	1,434	530
Total adjustments	\$ 1,123,552	\$ 668,351
Adjusted EBITDA	\$ 502,954	\$ 343,145
Weighted average shares outstanding - basic	844,080	793,542
Adjusted EBITDA per Share	\$ 0.60	\$ 0.43



ALTERNATIVE PERFORMANCE METRICS (FOR THE YEAR ENDED 31 DECEMBER 2022)(UNAUDITED)

Net Debt and Net Debt-to-Adjusted EBITDA

As used herein, Net Debt represents total debt as recognised on the balance sheet less cash and restricted cash. Total debt includes our borrowings under the Credit Facility and borrowings under or issuances of, as applicable, our subsidiaries' securitisation facilities. We believe Net Debt is a useful indicator of our Leverage and capital structure.

As used herein, Net Debt-to-Adjusted EBITDA, or "Leverage" or "Leverage Ratio," is measured as Net Debt divided by Adjusted EBITDA. We believe that this metric is a key measure of our financial Liquidity and flexibility and is used in the calculation of a key metric in one of our Credit Facility financial covenants.

	Year Ended	
	31 December 2022	31 December 2021
Cash	\$ (56,000)	\$ (570,600)
Credit Facility	(125,864)	(155,266)
ABS I Notes	(147,458)	(169,320)
ABS II Notes	(319,856)	-
ABS III Notes	(130,144)	-
ABS IV Notes	(378,796)	-
ABS V Notes	(212,446)	-
Term Loan I	(120,518)	(137,099)
Other	(7,084)	(9,380)
Total Debt	\$ (1,498,166)	\$ (1,041,665)
Cash	\$ 7,329	\$ 12,558
Restricted Cash	\$ 55,388	\$ 19,102
Net Debt	\$ (1,435,449)	\$ (1,010,005)
Adjusted EBITDA	\$ 502,954	\$ 343,145
Pro forma TTM Adjusted EBITDA^(a)	\$ 574,414	\$ 490,978
Net Debt-to-Pro forma TTM Adjusted EBITDA^(b)	2.5x	2.1x
Net Debt, inclusive of Tanos II pro forma adjustments^(c)	\$ (1,525,449)	
Pro forma Adjusted EBITDA, inclusive of Tanos II^(c)	\$ 681,414	
Net Debt-to-Pro forma Adjusted EBITDA, inclusive of Tanos II^(b)	2.2x	

Amounts in thousands, except per share and per unit data;

a) Pro forma Adjusted EBITDA includes adjustments for the year ended 31 December 2022 for the East Texas Assets and ConocoPhillips acquisitions to pro forma their results for a full twelve months of operations. Similar adjustments were made for the year ended 31 December 2021 for the Indigo Blackbeard, Tanos and Tapstone acquisitions as well as Oaktree's subsequent participation in the Indigo transaction.

b) Does not include adjustments for working capital which are often customary in the market.

c) Net Debt, inclusive of Tanos II pro forma adjustments, and Pro forma Adjusted EBITDA, inclusive of Tanos II, include adjustments for the year ended 31 December 2022 for the Tanos II transaction announced on February 1, 2023 to pro forma its expected results for a full twelve months of operations.



ALTERNATIVE PERFORMANCE METRICS (FOR THE YEAR ENDED 31 DECEMBER 2022)(UNAUDITED)

Total Revenue, Inclusive of Hedges and Adjusted EBITDA Margin

As used herein, Total Revenue, Inclusive of Hedges, includes the impact of derivatives settled in cash. We believe that Total Revenue, Inclusive of Hedges is a useful because it enables investors to discern our realised revenue after adjusting for the settlement of derivative contracts.

As used herein, Adjusted EBITDA Margin is measured as Adjusted EBITDA, as a percentage of Total Revenue, Inclusive of Hedges. Adjusted EBITDA Margin includes the direct operating cost and the portion of general and administrative cost it takes to produce each Boe. This metric includes operating expense, employees, administrative costs and professional services and recurring allowance for credit losses, which include fixed and variable costs components. We believe that Adjusted EBITDA Margin is a useful measure of our profitability and efficiency as well as our earnings quality because it measures the Group on a more comparable basis period-over-period, given we are often involved in transactions that are not comparable between periods.

	Year Ended	
	31 December 2022	31 December 2021
Total revenue	\$ 1,919,349	\$ 1,007,561
Net gain (loss) on commodity derivative instruments ^(a)	(895,802)	(320,656)
Total Revenue, Inclusive of Hedges	\$ 1,023,547	\$ 686,905
Adjusted EBITDA	\$ 502,954	\$ 343,145
Adjusted EBITDA Margin	49%	50%

Average Quarterly Dividend per Share

Average Quarterly Dividend per Share is reflective of the average of the dividends per share declared throughout the applicable fiscal year which gives consideration to changes in dividend rates and changes in the amount of shares outstanding. We use Average Quarterly Dividend per Share as we seek to pay a consistent and reliable dividend to shareholders.

	Year Ended	
	31 December 2022	31 December 2021
Declared on first quarter results	\$ 0.0425	\$ 0.0400
Declared on second quarter results	\$ 0.0425	\$ 0.0400
Declared on third quarter results	\$ 0.0438	\$ 0.0425
Declared on fourth quarter results	\$ 0.0438	\$ 0.0425
Average Quarterly Dividend per Share	\$ 0.0431	\$ 0.0413
Total Dividends per Share	\$ 0.1725	\$ 0.1650

Amounts in thousands, except per share and per unit data;

a) Net gain (loss) on commodity derivative settlements represents cash (paid) or received on commodity derivative contracts. This excludes settlements on foreign currency and interest rate derivatives as well as the gain (loss) on fair value adjustments for unsettled financial instruments for each of the periods presented.



ALTERNATIVE PERFORMANCE METRICS (FOR THE YEAR ENDED 31 DECEMBER 2022)(UNAUDITED)

Free Cash Flow

As used herein, Free Cash Flow represents net cash provided by operating activities less expenditures on natural gas and oil properties and equipment and cash paid for interest. We believe that Free Cash Flow is a useful indicator of our ability to generate cash that is available for activities other than capital expenditures. The Directors believe that Free Cash Flow provides investors with an important perspective on the cash available to service debt obligations, make strategic acquisitions and investments and pay dividends.

	Year Ended	
	31 December 2022	31 December 2021
Net cash provided by operating activities	\$ 387,764	\$ 320,182
LESS: Expenditures on natural gas and oil properties and equipment	(86,079)	(50,175)
LESS: Cash paid for interest	(82,936)	(41,623)
Free Cash Flow	\$ 218,749	\$ 228,384

Adjusted Operating Cost per Boe and Employees, Administrative Costs and Professional Services

Adjusted Operating Cost per Boe is a metric that allows us to measure the direct operating cost and the portion of general and administrative cost it takes to produce each Boe. This metric, similar to Adjusted EBITDA Margin, includes operating expense employees, administrative costs and professional services and recurring allowance for credit losses, which include fixed and variable cost components.

As used herein, employees, administrative costs and professional services represents total administrative expenses excluding cost associated with acquisitions, other adjusting costs and non-cash expenses. We use employees, administrative costs and professional services because this measure excludes items that affect the comparability of results or that are not indicative of trends in the ongoing business.

	Year Ended	
	31 December 2022	31 December 2021
Total production (MBoe)	49,354	43,257
Total operating expense	\$ 445,893	\$ 291,213
Employees, administrative costs and professional services	77,172	56,812
Recurring allowance for credit losses	0	-4265
Adjusted Operating Cost	\$ 523,065	\$ 343,760
Adjusted Operating Cost per BOE	\$10.60	\$7.95



REVENUE RECONCILIATION (NON-IFRS) (FOR THE YEAR ENDED 31 DECEMBER 2022)(UNAUDITED)

	FY21	1Q22	2Q22	3Q22	4Q22	FY22	Units	Per Unit					
								FY21	1Q22	2Q22	3Q22	4Q22	FY22
Production:													
Natural gas (MMcf)	234,643	62,419	64,979	64,344	63,854	255,597							
Oil (MBbls)	592	385	401	378	390	1,554							
NGL (MBbls)	3,558	1,258	1,343	1,283	1,317	5,200							
Total MBOE	43,257	12,046	12,574	12,385	12,349	49,354							
MBOED	118.5	133.8	138.2	134.6	398.4	135.2							
Unhedged revenue & EBITDA:													
Natural gas	\$ 813,786	\$ 287,742	\$ 433,138	\$ 472,804	\$ 350,974	\$ 1,544,658	mcf	\$ 3.47	\$ 4.61	\$ 6.67	\$ 7.35	\$ 5.50	\$ 6.04
Oil	38,634	35,224	43,593	31,273	29,531	139,620	bbl	65.26	91.49	108.71	82.73	75.72	89.85
NGL	120,686	57,787	56,331	42,191	32,424	188,733	bbl	33.92	45.94	41.95	32.89	24.63	36.30
Commodity revenue (unhedged)	973,106	380,753	533,062	546,268	412,929	1,873,011	boe	22.50	31.61	42.39	44.11	33.44	37.95
Midstream revenue	31,986	8,944	7,658	8,673	7,511	32,798	boe	0.74	0.74	0.61	0.70	0.61	0.66
Other revenue	2,468	747	329	753	2,513	4,331	boe	0.06	0.06	0.03	0.06	0.20	0.09
Total revenue (unhedged)	1,007,560	390,444	541,049	555,694	422,953	1,910,140	boe	23.29	32.41	43.03	44.87	34.25	38.70
EBITDA (unhedged)	663,800	274,254	416,819	420,476	285,206	1,396,752	boe	\$ 15.35	\$ 22.77	\$ 33.15	\$ 33.95	\$ 23.10	\$ 28.30
Expenses:													
Operational expenses	291,213	97,586	106,589	115,167	116,874	436,216	boe	\$ 6.73	\$ 8.10	\$ 8.48	\$ 9.30	\$ 9.46	\$ 8.84
Administrative expenses (recurring)	52,547	18,604	17,641	20,052	20,873	77,172	boe	1.21	1.54	1.40	1.62	1.69	1.56
Total expenses	343,760	116,190	124,230	135,219	137,747	513,388	boe	\$ 7.95	\$ 9.65	\$ 9.88	\$ 10.92	\$ 11.15	\$ 10.40
Settled hedges:													
Gas	\$(263,929)	\$(123,479)	\$(261,707)	\$(263,645)	\$(133,692)	\$ (782,525)	mcf	\$ (1.12)	\$ (1.98)	\$ (4.03)	\$ (4.10)	\$ (2.09)	\$ (3.06)
Oil	3,804	(8,177)	(10,714)	(5,888)	(2,949)	(27,728)	bbl	6.43	(21.24)	(26.72)	(15.58)	(7.56)	(17.84)
NGL	(60,531)	(32,996)	(31,658)	(15,162)	(5,733)	(85,549)	bbl	(17.01)	(26.23)	(23.57)	(11.82)	(4.35)	(16.45)
Total gain (loss)	\$(320,656)	\$(164,652)	\$(304,079)	\$(284,695)	\$(142,374)	\$ (895,802)	boe	\$ (7.41)	\$ (13.67)	\$ (24.18)	\$ (22.99)	\$ (11.53)	\$ (18.15)
Hedged revenue & EBITDA:													
Natural gas	\$ 549,857	\$ 164,263	\$ 171,431	\$ 209,159	\$ 217,282	\$ 762,133	mcf	\$ 2.34	\$ 2.63	\$ 2.64	\$ 3.25	\$ 3.40	\$ 2.98
Oil	42,438	27,047	32,879	25,385	26,582	111,892	bbl	71.69	70.25	81.99	67.16	68.16	72.00
NGL	60,155	24,791	24,673	27,029	26,691	103,184	bbl	16.91	19.71	18.37	21.07	20.27	19.84
Commodity revenue (hedged)	652,450	216,101	228,983	261,573	270,555	977,209	boe	15.08	17.94	18.21	21.12	21.91	19.80
Midstream revenue	31,986	8,944	7,658	8,673	7,511	32,798	boe	0.74	0.74	0.61	0.70	0.61	0.66
Other revenue	2,468	747	329	753	2,513	4,331	boe	0.06	0.06	0.03	0.06	0.20	0.09
Total revenue (hedged)	686,904	225,792	236,970	270,999	280,579	1,014,338	boe	15.88	18.74	18.85	21.88	22.72	20.55
Gain on Land Sale	-	-	1,565	907	-	2,472	boe	-	-	0.12	0.07	-	0.05
EBITDA (hedged)	\$ 343,144	\$ 109,602	\$ 114,304	\$ 136,688	\$ 142,832	\$ 503,422	boe	\$ 7.93	\$ 9.10	\$ 9.09	\$ 11.04	\$ 11.57	\$ 10.20



EXPENSE RECONCILIATION (NON-IFRS) (FOR THE YEAR ENDED 31 DECEMBER 2022)(UNAUDITED)

	FY21	1Q22	2Q22	3Q22	4Q22	FY22	Units	FY21	1Q22	2Q22	Per Unit 1H22	3Q22	Q4	FY22
Production:														
Natural gas (MMcf)	234,643	62,419	64,979	64,344	63,854	255,597								
Oil (MBbls)	592	385	401	378	390	1,554								
NGL (MBbls)	3,558	1,258	1,343	1,283	1,317	5,200								
Total MBOE	43,257	12,046	12,574	12,385	12,349	49,354								
MBOED	118.5	133.8	138.2	134.6	134.2	135.2								
Revenue:														
Natural Gas	\$ 813,786	\$ 287,742	\$ 433,138	\$ 472,804	\$ 350,974	\$ 1,544,658	mcf	\$ 3.47	\$ 4.61	\$ 6.67	\$ 5.66	\$ 7.35	\$ 5.50	\$ 6.04
Oil	38,634	35,224	43,593	31,273	29,531	139,620	bbl	65.26	91.49	108.71	#####	82.73	75.72	89.85
NGL	120,686	57,787	56,331	42,191	32,424	188,733	bbl	33.92	45.94	41.95	43.88	32.89	24.63	36.30
Total commodity revenue	973,106	380,753	533,062	546,268	412,929	1,873,011	boe	22.50	31.61	42.39	37.12	44.11	33.44	37.95
Midstream revenue	31,986	8,944	7,658	8,673	7,511	32,798	boe	0.74	0.74	0.61	0.67	0.70	0.61	0.66
Other	2,468	747	329	753	2,513	4,331	boe	0.06	0.06	0.03	0.13	0.06	0.20	0.09
Total revenue (unhedged)	\$ 1,007,560	\$ 390,444	\$ 541,049	\$ 555,694	\$ 422,953	1,910,140	boe	\$ 23.29	\$ 32.41	\$ 43.03	#####	\$ 44.87	\$ 34.25	\$ 38.70
Settled hedges	(320,656)	(164,652)	(304,079)	(284,696)	(142,374)	(895,802)	boe	(7.41)	(13.67)	(24.18)	(19.04)	(22.99)	(11.53)	(18.15)
Total revenue (hedged)	686,904	225,792	236,970	270,999	280,579	1,014,338	boe	15.88	18.74	18.85	18.88	21.88	22.72	20.55
Operating expenses & gross profit:														
Base LOE	119,594	39,372	40,222	44,845	48,702	173,140	boe	2.76	3.27	3.20	3.32	3.62	3.94	3.51
Midstream expense	60,481	16,124	17,032	19,369	18,628	71,154	boe	1.40	1.34	1.35	1.35	1.56	1.51	1.44
Gathering and transportation	80,620	27,185	30,362	29,822	30,705	118,073	boe	1.86	2.26	2.41	2.34	2.41	2.49	2.39
Production taxes	30,518	14,905	18,973	21,131	18,839	73,849	boe	0.71	1.24	1.51	1.38	1.71	1.53	1.50
Total operating expenses (a)	291,213	97,586	106,589	115,167	116,874	436,216		6.73	8.10	8.48	8.38	9.30	9.46	8.84
Gross profit (unhedged)	716,347	292,858	434,460	440,528	306,079	1,473,924	boe	16.56	24.31	34.54	29.54	35.59	24.73	29.85
G&A & total expense:														
Total administrative expenses	98,061	84,605	29,677	30,243	26,209	170,735	boe	2.27	7.02	2.36	4.64	2.44	2.12	3.46
Total expenses	389,274	182,191	136,266	145,410	143,083	606,951	boe	9.00	15.12	10.84	13.02	11.74	11.59	12.30
Acquisition and integration costs	38,115	64,494	9,474	8,324	3,221	85,512		0.88	5.35	0.75	3.00	0.67	0.26	1.73
Provision for owner int rec	-	-	-	-	-	-		-	-	-	-	-	-	-
Non-cash equity compensation	7,400	1,507	2,562	1,867	2,115	8,051	boe	0.17	0.13	0.20	0.17	0.15	0.17	0.16
Total G&A adjustments	45,515	66,001	12,036	10,191	5,336	93,563	boe	1.05	5.48	0.96	3.17	0.82	0.43	1.90
Administrative expenses (recurring)	52,547	18,604	17,641	20,052	20,873	77,172	boe	1.21	1.54	1.40	1.47	1.62	1.69	1.56
Total expenses (recurring)	343,760	116,190	124,230	135,219	137,747	513,388	boe	7.95	9.65	9.88	9.85	10.92	11.15	10.40
Gain on Land Sale	-	-	1,565	907	-	2,472	boe	-	-	0.12		0.07	-	0.05
EBITDA:														
Adjusted EBITDA (unhedged)	663,800	274,254	418,383	421,383	285,206	1,399,224	boe	15.35	22.77	33.27	28.07	34.02	23.10	28.35
Settled hedges	(320,656)	(164,652)	(304,079)	(284,695)	(142,374)	(895,801)	boe	(7.41)	(13.67)	(24.18)	(19.04)	(22.99)	(11.53)	(18.15)
Adjusted EBITDA (hedged)	\$ 343,144	\$ 109,602	\$ 114,304	\$ 136,688	\$ 142,832	\$ 503,422	boe	\$ 7.93	\$ 9.10	\$ 9.09	\$ 9.03	\$ 11.04	\$ 11.57	\$ 10.20

Amounts in thousands unless otherwise noted; Excludes the impact of Next Level Energy for comparative purposes

a) Certain expense reclassifications were made to confirm previously reported results to current presentation