FY 2024 Earnings Presentation

February 2025

Crescent Energy

Disclaimer

The information in this presentation relates to Crescent Energy Company (the “Company,” “Crescent,” “we,” “us,” “our” or “CRGY”) and contains information that includes or is based upon “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical fact, included in this presentation, including statements regarding business, strategy, financial position, prospects, plans, objectives, forests and projections of the Company, are forward-looking statements. The words such as “estimate,” “budget,” “projection,” “would,” “project,” “predict,” “believe,” “expect,” “potential,” “should,” “could,” “may,” “plan,” “will,” “guidance,” “outlook,” “goal,” “future,” “assume,” “focus,” “work,” “commitment,” “approach,” “continue” and similar expressions are intended to identify forward-looking statements, however forward-looking statements are not limited to statements that contain these words. The forward-looking statements contained herein are based on management’s current expectations and beliefs concerning future events and their potential effect on the Company and involve known and unknown risks, uncertainties and assumptions, which may cause actual results to differ materially from results expressed or implied by the forward-looking statements.

These risks include, among other things, the imprecise nature of estimating oil and gas reserves; our ability to identify and select possible additional acquisition and disposition opportunities; the ability to integrate operations or realize any anticipated operational or corporate synergies and other benefits from the acquisition of Ridgemar and the acquisition of SilverBow; unexpected operating conditions and results; embargoes, political and regulatory developments resulting from the U.S. presidential transition; weather, political, and general economic conditions, including the impact of sustained cost inflation, elevated interest rates and associated changes in monetary policy; federal and state regulations and laws; the impact of disruptions in the capital markets; geopolitical events such as the armed conflict in Ukraine, the Israel-Hamas conflict and increased hostilities in the Middle East, including heightened tensions with Iran, Lebanon and Yemen; actions by the Organization of the Petroleum Exporting Countries (“OPEC”) and non-OPEC oil-producing countries, including extensions of production cuts by OPEC; the availability of drilling, completion and operating equipment and services; reliance on the Company’s external manager; commodity price volatility, the severity and duration of public health crises; and the risks associated with commodity pricing and the Company’s hedging strategy. The Company believes that all such expectations and beliefs are reasonable, but such expectations and beliefs may prove inaccurate. Many of these risks, uncertainties and assumptions are beyond the Company’s ability to control or predict. Because of these risks, uncertainties and assumptions, readers are cautioned not to, and should not, place undue reliance on these forward-looking statements. The Company does not give any assurance (1) that it will achieve its expectations or (2) to any business strategies, earnings or revenue trends or future financial results. The forward-looking statements contained herein speak only as of the date of this presentation. Although the Company may from time to time voluntarily update its prior forward-looking statements, it disclaims any commitment to correct, revise or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. All subsequent written and oral forward-looking statements concerning the Company or other matters and attributable thereto or to any person acting on its behalf are expressly qualified in their entirety by the cautionary statements above. For further discussions of risks and uncertainties, you should refer to the Company’s filings with the U.S. Securities and Exchange Commission (“SEC”) that are available on the SEC’s website at http://www.sec.gov, including the “Risk Factors” section of the Company’s most recent Annual Report on Form 10-K and any subsequently filed Quarterly Reports on Form 10-Q.

This presentation provides disclosure of the Company’s proved reserves. Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Unless otherwise indicated, reserve and PV-10 estimates shown herein are based on a reserves report as of December 31, 2024, prepared by the Company’s independent reserve engineer in accordance with applicable rules and guidelines of the SEC. SEC pricing was calculated using the simple average of the first-of-the-month commodity prices for 2024, adjusted for location and quality differentials, with consideration of known contractual price changes.

This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles (“GAAP”). These measures include (i) Adjusted EBITDAX, (ii) Net Debt, (iii) Levered Free Cash Flow, (iv) Adjusted Recurring Cash G&A, (v) Adjusted Operating Expense Excluding Production & Other Taxes, (vi) Net LTM Leverage and (vii) PV-10. See the Appendix of this presentation for definitions and discussion of the Company’s non-GAAP metrics and reconciliations to the most comparable GAAP metrics. These non-GAAP financial measures are not measures of financial performance prepared or presented in accordance with GAAP and may exclude items that are significant in understanding and assessing the Company’s financial results. Therefore, these measures should not be considered in isolation, and users of any such information should not place undue reliance thereon. Forward-looking metrics/guidance on Levered Free Cash Flow are not used in this presentation. Forward-looking non-GAAP financial measures provided without the most directly comparable GAAP financial measures may vary materially from the corresponding GAAP financial measures.

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2024 Recap: Delivering On All Strategic Priorities

Robust Financial Performance	• Consistent "beat and raise" • Met or exceeded guidance across key metrics
Solid Operational Execution	• Improved D&C costs and increased well productivity • Seamless integration; increased synergy expectations
Accretive Growth Through M&A	• >$3 BN of accretive Eagle Ford M&A across 5 deals • ~$250 MM divestiture pipeline; $50 MM sold in 2024
Attractive Return of Capital	• ~3% fixed dividend yield[(1)]; ~4% inclusive of buyback[(2)] • ~$30 MM repurchased at WA share price of $10.07
Capital Markets Progress	• Included in S&P SmallCap 600 Index • Substantial increase in public float and trading liquidity

(1) *Dividend yield based on CRGY share price of $14.66 as of 2/7/25.*
(2) *2024 yield based on CRGY share price of $14.66 as of 2/7/25.*

CRGY Performance: Strong Q4 Results

Substantial Cash Flow Generation

$535 MM Adj. EBITDAX(1)

$259 MM Levered FCF(1)

Large, Low Decline Base Production

255 Mboe/d

38% Oil / 56% Liquids

Attractive Return of Capital

$0.12/sh Fixed Quarterly Dividend(2)

~4% Annual Yield(3)

Balance Sheet Strength

~1.4x Net LTM Leverage(1)(4)

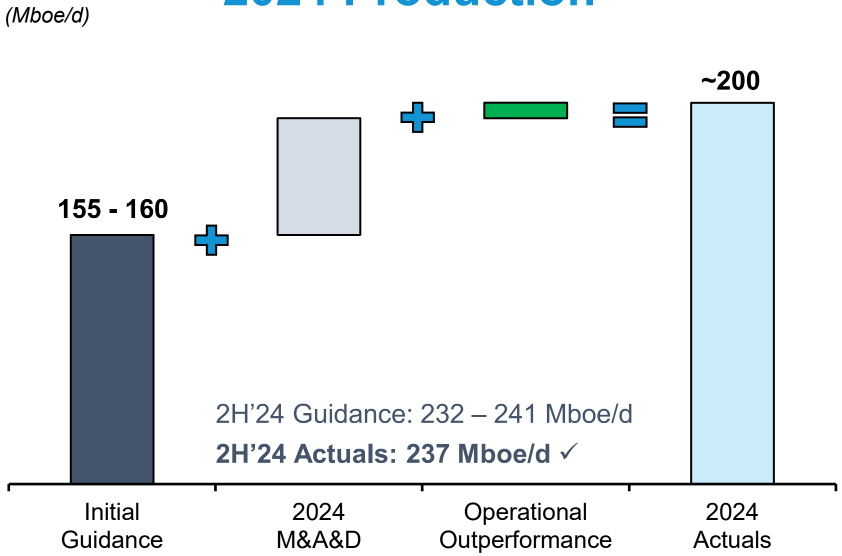
~$1.4 BN Liquidity(5)

(1) Non-GAAP financial measure. For a reconciliation to the comparable GAAP measure, see Appendix.
(2) Any payment of future dividends is subject to Board approval and other factors.
(3) 2024 yield - inclusive of buyback. Based on CRGY share price of $14.66 as of 2/7/25.
(4) As of 12/31/24.
(5) Liquidity pro forma for closing of acquisition of Ridgemar and based on 1/31/25 RBL Elected Commitment of $2.0 BN less amount drawn less outstanding letters of credit plus cash outstanding as of 1/31/25.

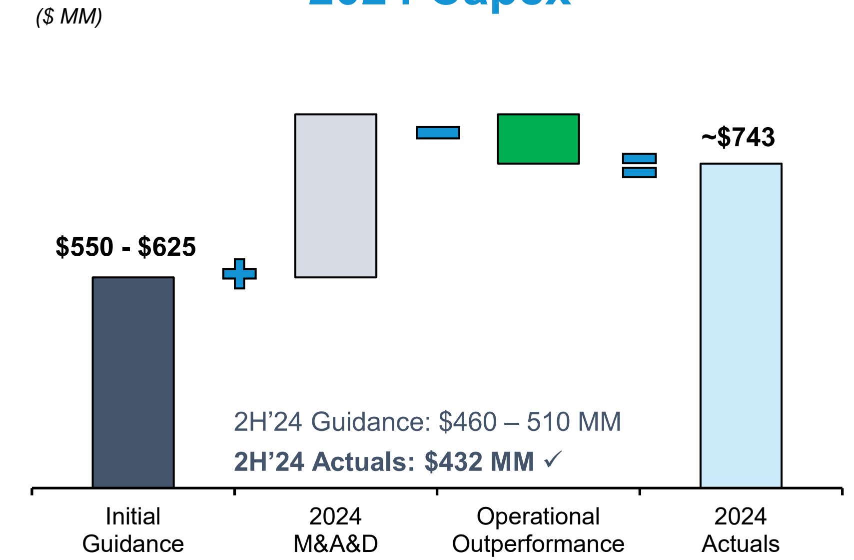
2024 Financial Performance Exceeds Expectations

Significant Growth and Free Cash Flow Generation in Transformational Year

2024 Production



2024 Capex



Production Outperformance

Increasing Eagle Ford well productivity year-over-year

Operational Outperformance

D&C cost execution driving increased capital efficiency

Significant FCF Generation(1)

>10% beat on consensus Free Cash Flow estimates(2)

Note: All amounts are approximations based on currently available information and estimates and are subject to change based on events and circumstances after the date hereof. See "Disclaimer."
(1) Non-GAAP financial measure. For a reconciliation to the comparable GAAP measure, see Appendix.
(2) FY'24 Consensus Wall Street research estimates as of 2/10/25 per FactSet.

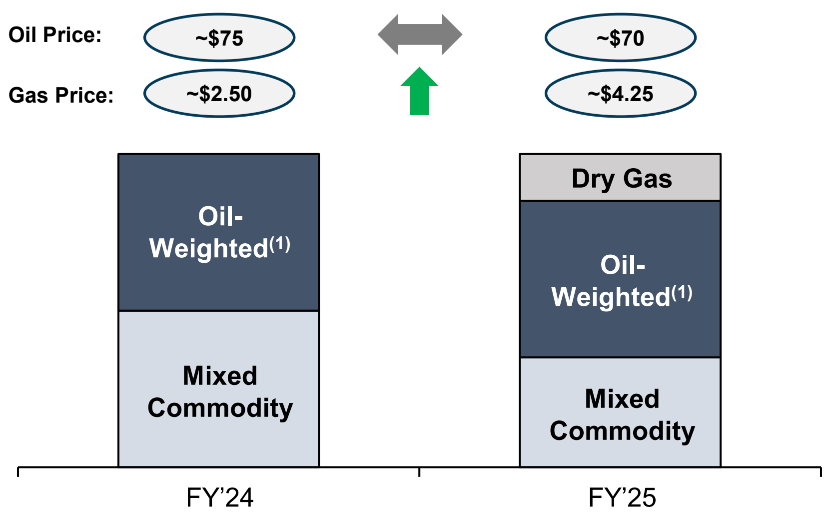
2025 Plan Highlights Flexible Capital Allocation and Significant Free Cash Flow Generation

Flexibility: Largely HBP assets with ability to invest across oil or gas focused inventory to maximize returns across commodity cycles

Free Cash Flow: Significant FCF generation to support the base dividend, debt paydown and further accretive growth through M&A

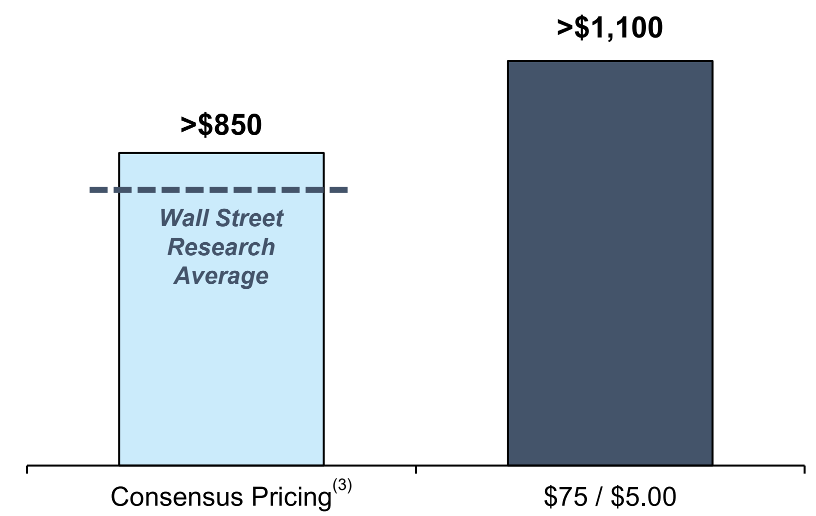
Development Capital Allocation

(% of Annual Program)



2025E FCF Generation[2]

($ in MM)



Capitalizing on Advantaged Commodity Flexibility

Maximizing Sustainable Free Cash Flow Generation

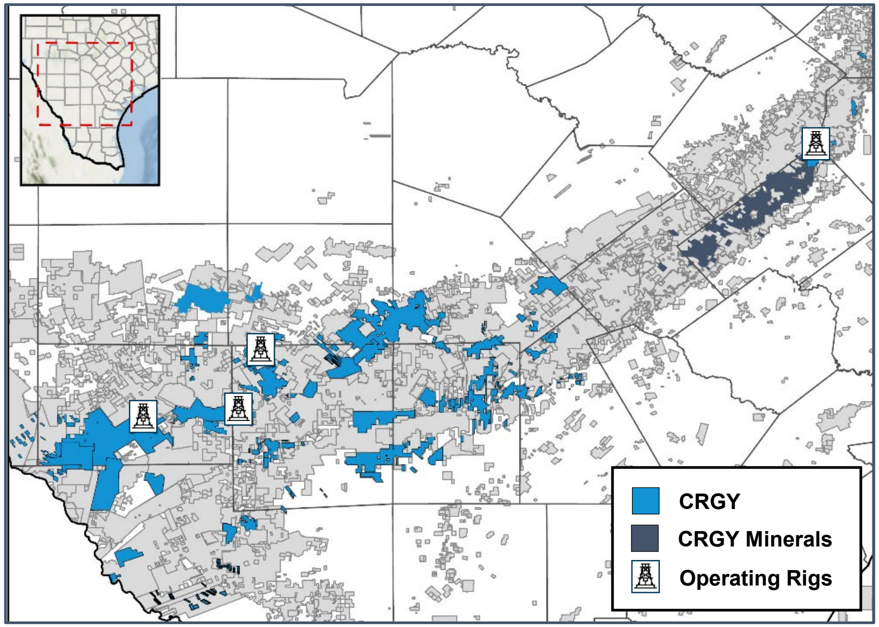
(1) Oil-Weighted includes Central EGF oil and Uinta development capital.
(2) Includes the impact of hedges.
(3) Consensus pricing based on Wall Street consensus estimates as of 2/25/25.

Eagle Ford Quarterly Highlights:
Premier Position with Attractive Commodity Diversification

Scaled Footprint with Significant Incremental Growth Opportunity

- ☑ **Increasing Year-Over-Year Well Productivity**
- ☑ **Continued D&C Cost Improvement and Margin Expansion**
- ☑ **Capturing Gas Optionality with 2025 Gas-Focused Capital**
- ☑ **Closed $905 MM Ridgemar Acquisition and ~$21 MM Dry Gas Acquisition on 1/31**

Eagle Ford Acreage(1)



Q4 Operational Results(2)

Net Production	*Mboe/d*	~155
	% Oil	~37%
Capital Spend – $ MM		~$166
D&C Activity *(Gross / Net)*	*Spuds*	18 / ~13
	TiLs	15 / ~12

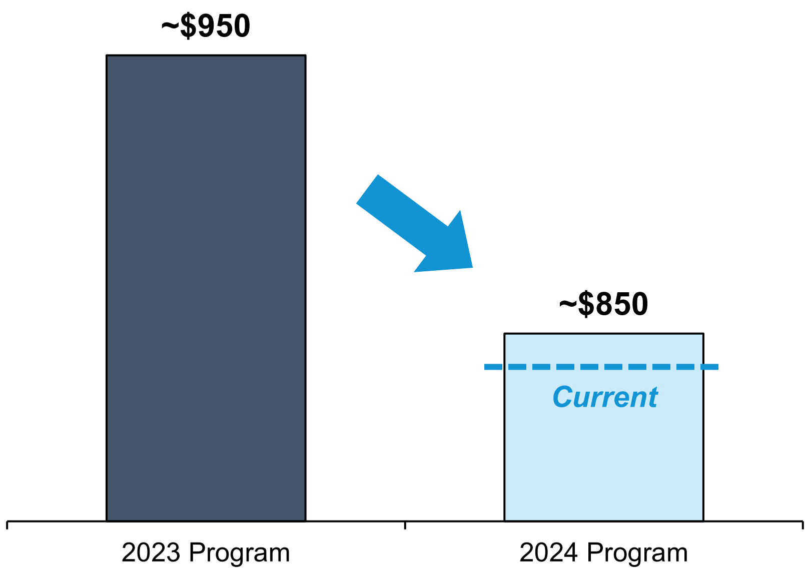
(1) As of 12/31/24. Pro forma Ridgemar.
(2) Does not include Ridgemar acquisition or dry gas acquisition that closed on 1/31/25.

Strong Eagle Ford Momentum: Positive Rate of Change

Generating More with Less – Increasing Returns with Capital Efficiencies and Positive Well Productivity Trajectory

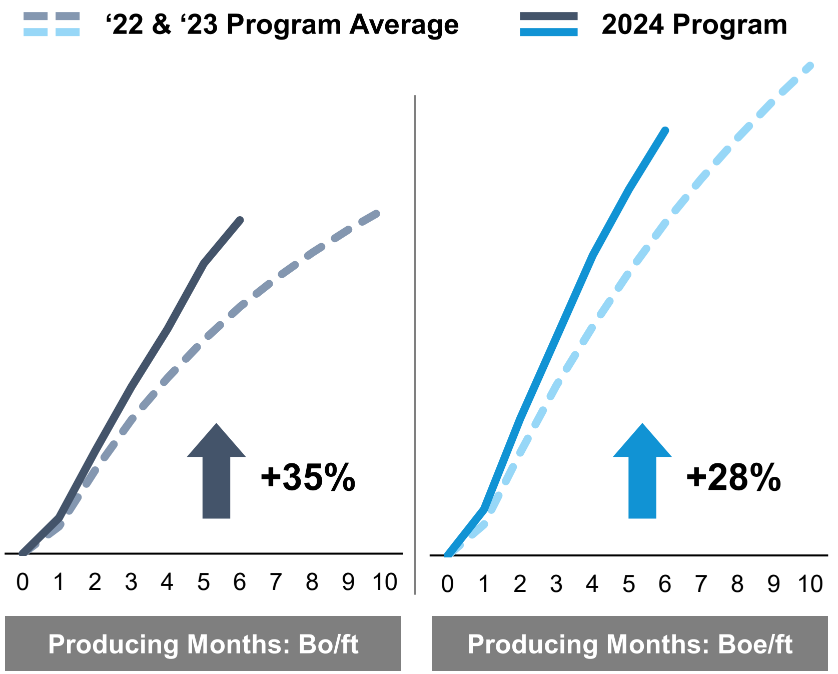
CRGY Capital Efficiency

(Drilling, Completions and Facilities - $/ft)



CRGY Well Performance

(Avg Cum. Prod/ft)[1]



~10% | **Improvement in CRGY Eagle Ford Well Costs Year-Over-Year**

~30% | **Increase in CRGY Eagle Ford Well Performance Year-Over-Year**

Source: Enverus. All data includes cost and well performance from acquired assets prior to CRGY operatorship.
(1) Cumulative production comparison based on 6-month cumulative performance.

Applying Operational Best Practices to Lower D&C Costs

Completed First Advanced Trajectory Wells on Legacy CRGY Assets

12 Advanced Trajectory[1] Wells, Including 7 Full U-Turns on the Crescent Footprint

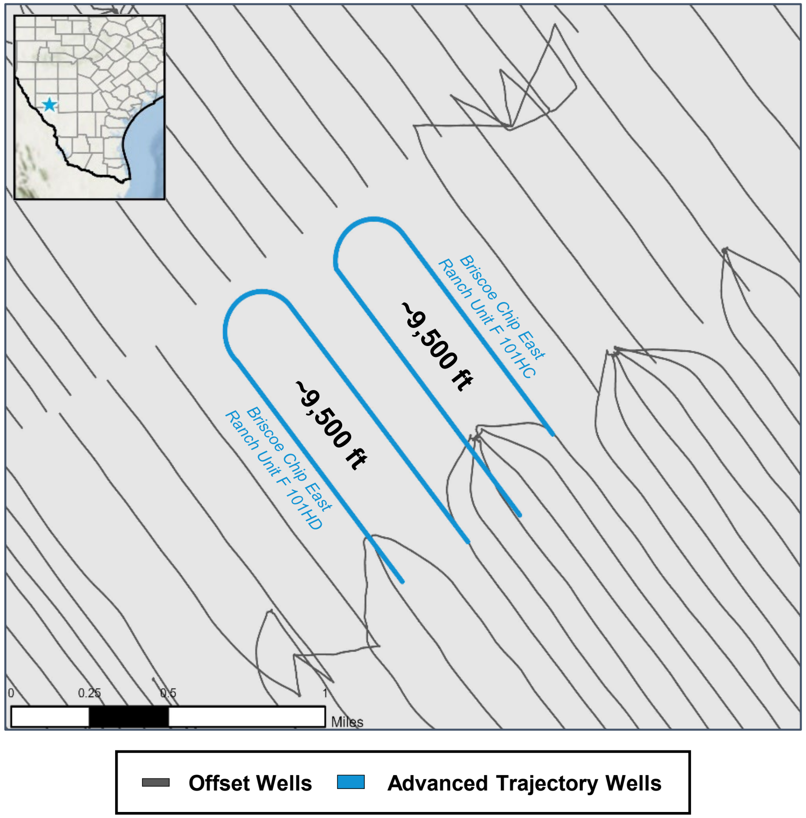
- **~$2 MM in savings per well vs. traditional development**

Frac'ing the "Curve" Allows for Production Contribution from the Entire Lateral

Production per Foot In-Line with Traditional Lateral Development

- **Optimizing economics on complex acreage**

Recent WEF U-Turn Wells[2]



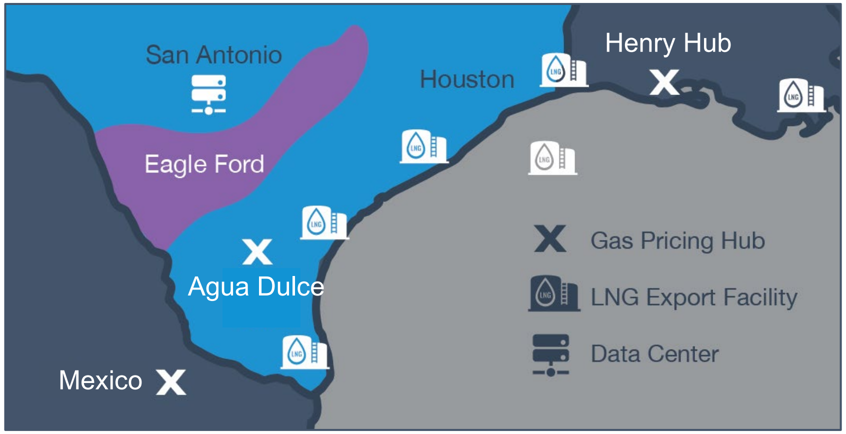
(1) *Advanced trajectory defined as wells with greater than 30 degree deviation mid-lateral.*
(2) *No internal company planned wellbores or directional wellbores were changed in the databases for completion of this map.*

Capitalizing on Premier South Texas Gas Optionality

Allocating a Portion of 2025 Capital to Eagle Ford Dry Gas Development

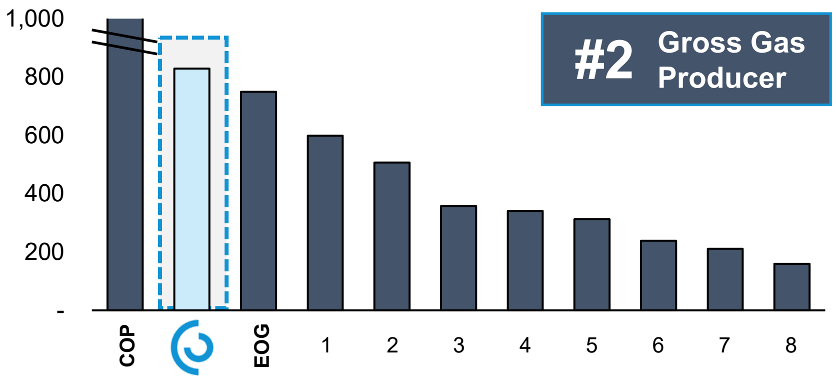
- **Advantaged Market Access with Increasing Demand from LNG & Data Center Expansion**
- **Established Infrastructure with Ample Takeaway Capacity**
- **Short-Cycle Inventory Well-Positioned to Capture Upward Gas Price Volatility**
- **Recent Webb County Bolt-On Increases Working Interest on Existing Acreage**

Advantaged Market Access(1)



Eagle Ford Gas Production(2)

(Gross Operated - MMcf/d)



(1) Map is not to scale and for illustrative purposes.
(2) Source: Enverus as of 1/28/25. Based on trailing 3 month average production for months with complete data (August-October). Includes largest 10 operators besides pro forma CRGY. Peers include BP, COP, DVN, EOG, KTG, Lewis, MGY, SM, Trinity and Verdun.

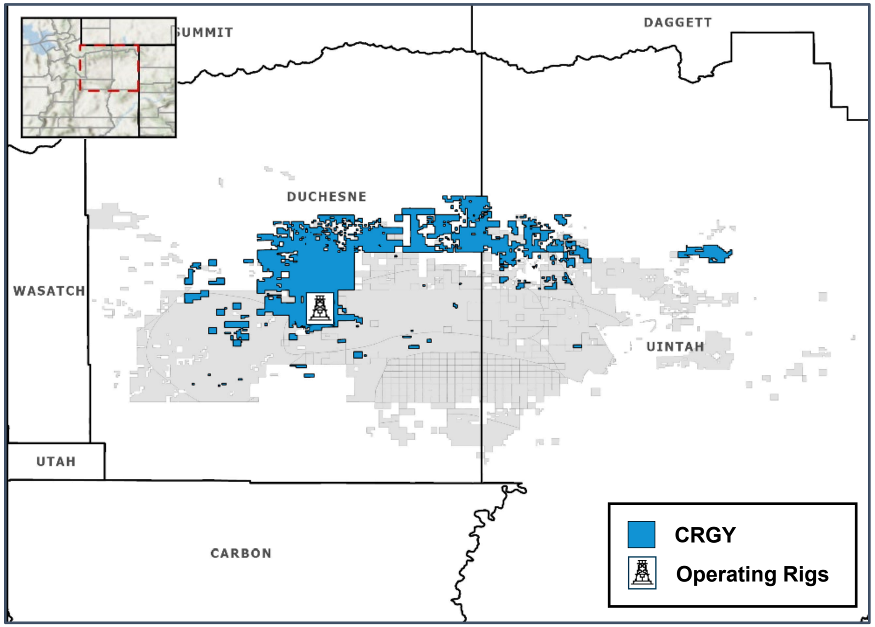
Uinta Quarterly Highlights:

HBP Asset Base with Substantial Stacked Resource Opportunity

Acquired Asset in Q1'22 for Production Value; Driving Incremental Returns Through Attractive Development

- **Development Program Generating Attractive Returns**
- **Prudently Delineating Substantial Stacked Resource Opportunity**
  - **~25% of 2024 program allocated to non-Uteland Butte intervals**
- **Expanding Eastern Resource Potential Through JV with No Upfront Capital**

Uinta Acreage[1]



Q4 Operational Results

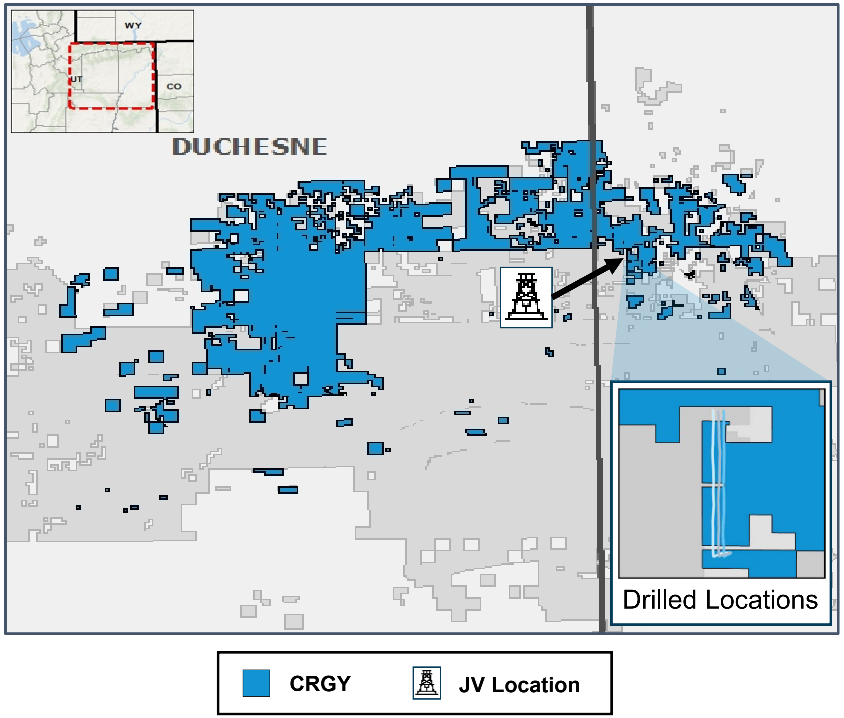
Net Production	*Mboe/d*	**~26**
	% Oil[2]	**~63%**
Capital Spend – $ MM		**~$39**
D&C Activity *(Gross / Net)*	*Spuds*	**4 / ~4**
	TiLs	**5 / ~5**

(1) *As of 12/31/24.*
(2) *Future development inventory is ~80% oil.*

Impressive Early Time Results from Eastern Uinta JV

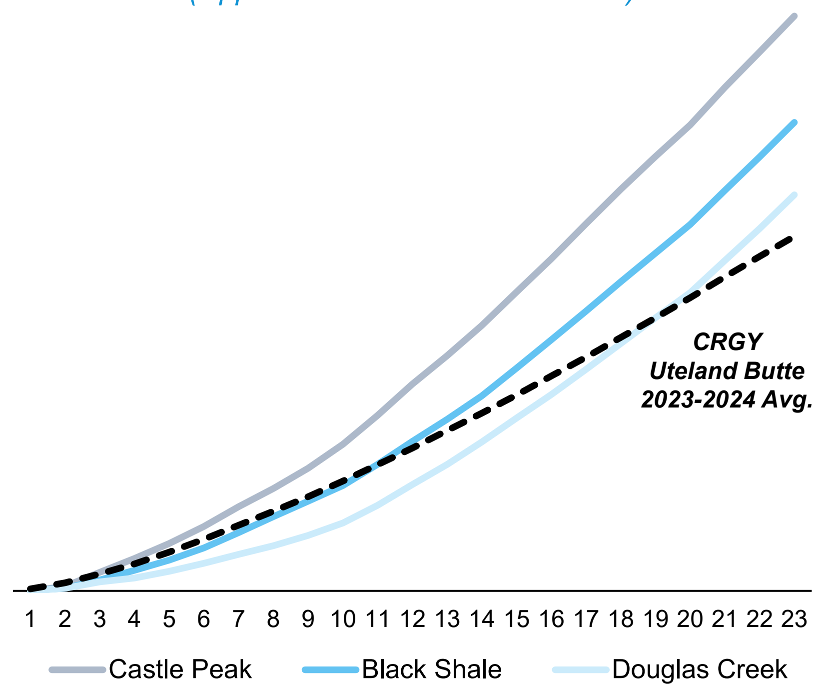
Executing on Prudent Delineation of Substantial Stacked Resource Opportunity

Eastern Uinta Joint Venture



Strong Eastern Performance

(Upper Cube Results - Cum. Bo/ft)



Derisking Significant Eastern Resource Without Upfront Capital Spend

~1,500 Bo/d

Average IP30 Results per Well Exceeding Core Uteland Butte Development

Successful Track Record of Accretive Acquisitions

More Than Doubled in Scale Since Public Listing Through Consistent Execution

Focused in Regions Where We Currently Operate

- **Eagle Ford & Rockies**

Consistent Underwriting Criteria

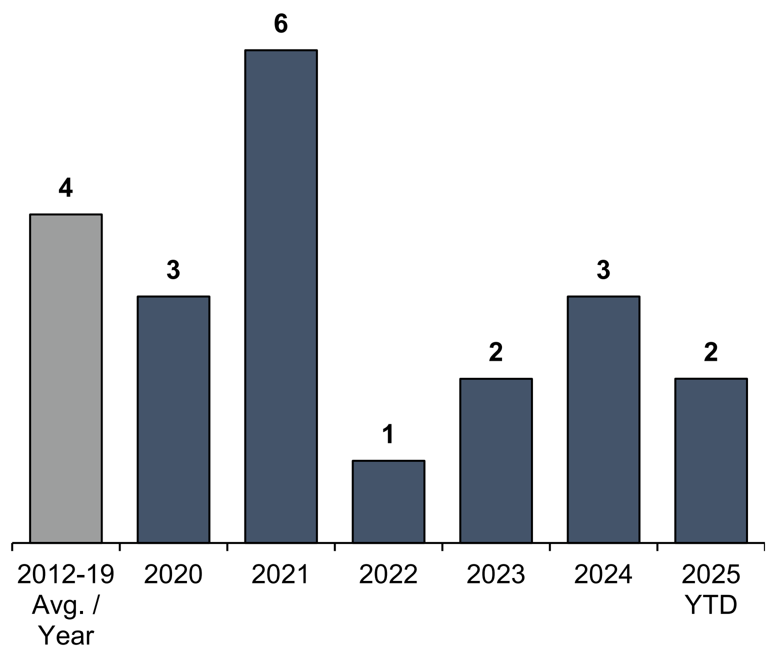
- **Cash-on-cash returns, equity accretion and strong balance sheet**

Driving Incremental Returns with Improved Performance and Synergies

- **Strong operational performance drives M&A success**

Proven Acquisition Strategy(1)

(Crescent Acquisitions)



~30% | **Production CAGR (2020 – Current)(2)**

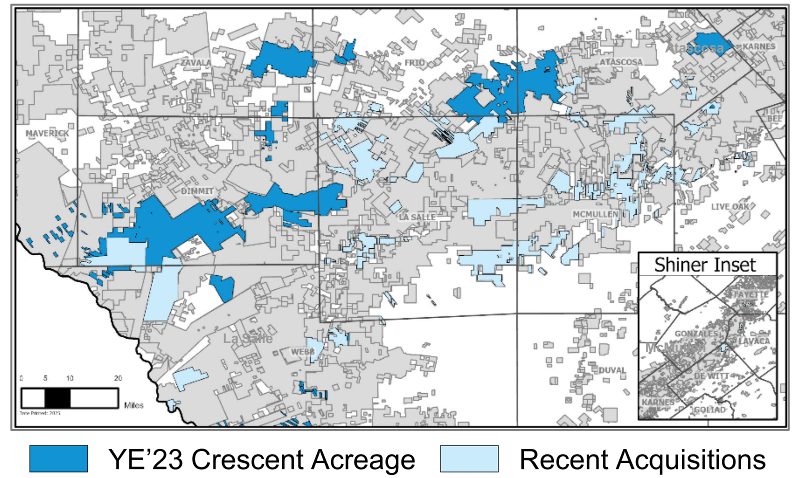
(1) *Acquisition history represents Crescent and its predecessors. Acquisitions grouped by closing date.*
(2) *Based on production metrics from 2020 to pro forma current.*

Transformative Eagle Ford Growth Through M&A

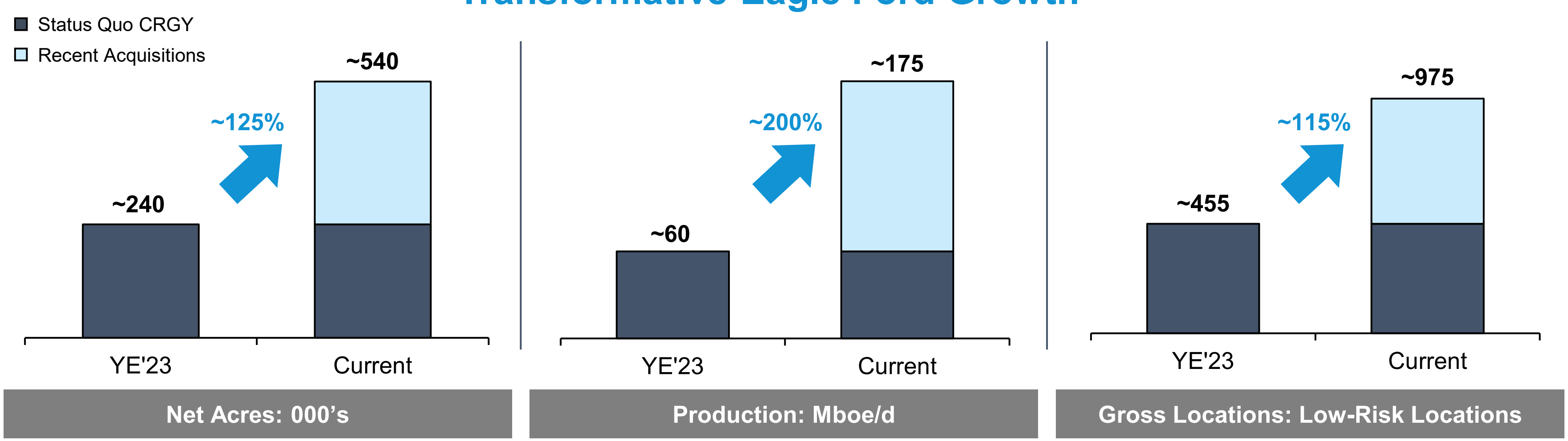
More Than Doubled Eagle Ford Footprint Through 5 Transactions Since YE'23

- **Transforming CRGY Position in a Premier Basin**
- **Weighted Average Entry Valuation of <3.0x EBITDA**
- **Compounding Synergies with Efficient Integration**

CRGY Eagle Ford Footprint



Transformative Eagle Ford Growth[1]



(1) YE'23 metrics represent metrics as of December 2023. Current metrics represent metrics as of December 2024, pro forma for closing of the Ridgemar acquisition.

Driving Shareholder Value Through Seamless Integration

SilverBow Acquisition Continuing to Outperform Expectations; Achieved Increased Synergy Range Ahead of Schedule, with Further Value Expected

- Expect ~$15 - 20 MM of annual Ridgemar synergies

(Annual - $ MM)	Initial Target	Q3'24 Update	Captured To-Date	Current Target	Synergy Progress
Cost of Capital	$25 - 45	$36	***~$36***	$36	• Fully realized cost-of-capital savings from successful HY offerings and improved RBL pricing
Overhead *(G&A & LOE)*	~$10	$15	***~$15***	$15	• Redesigned combined operating organization for increased efficiency • Eliminated duplicative services and functions
Operational *(D&C & LOE)*	$30 - 45	$40 - 60	***~$55***	$55 - 70	• Re-bid vendor contracts, leveraging relationships from both legacy companies • Applying CRGY efficiencies to legacy SBOW assets • Optimized oil marketing across full asset base to improve netbacks
Total Synergies	**$65 - 100**	**$90 - 110**	***~$106***	**$106 - 120**	**Anticipate full realization by year-end 2025**

Note: Numbers may not sum due to rounding.

“BB” Balance Sheet Reflects Financial Strength

Targeting Investment Grade Balance Sheet Metrics Through Cycles

Maintain Ample Liquidity: **Current liquidity is ~3x our >$500 MM target**

Balance Sheet Flexibility: **No near-term maturities**

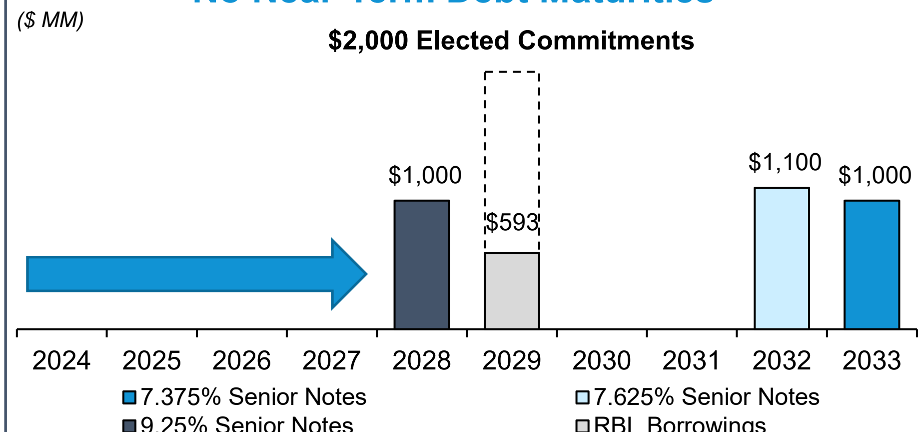
Active Hedge Program: **Reduces cash flow variability and supports balance sheet**

Opportunistic Portfolio Optimization: **Non-core divestitures can accelerate debt paydown; $50 MM in 2024**

Commitment to Balance Sheet Strength

Current Leverage[1]	Leverage Target / Max	Total Liquidity[2]
~1.4x	1.0x / 1.5x	~$1.4BN
Fitch[3] BB- / BB-	**Moody’s[3] Ba3 / B1**	**S&P[3] B+ / BB-**
Outlook: Stable	Outlook: Stable	Outlook: Positive

No Near-Term Debt Maturities[4]



(1) Crescent defines Net LTM Leverage as the ratio of consolidated net debt to consolidated Adjusted EBITDAX (non-GAAP) as defined and calculated under its Revolving Credit Facility. Net LTM Leverage is a non-GAAP financial measure. For a reconciliation to the comparable GAAP measure, see Appendix.
(2) Liquidity pro forma for closing of acquisition of Ridgemar and based on 1/31/25 RBL Elected Commitment of $2.0 BN less amount drawn less outstanding letters of credit plus cash outstanding as of 1/31/25.
(3) See “Credit Ratings” in Disclaimer on page 2 for additional information on credit ratings.
(4) Estimated net debt as of 1/31/25. RBL borrowings net of cash on the balance sheet.

Decade-Plus History of Returning Cash to Shareholders

Providing Shareholders with Consistent and Attractive Fixed Dividend

Return of Capital Framework:

Priority **#1**

Fixed Dividend:

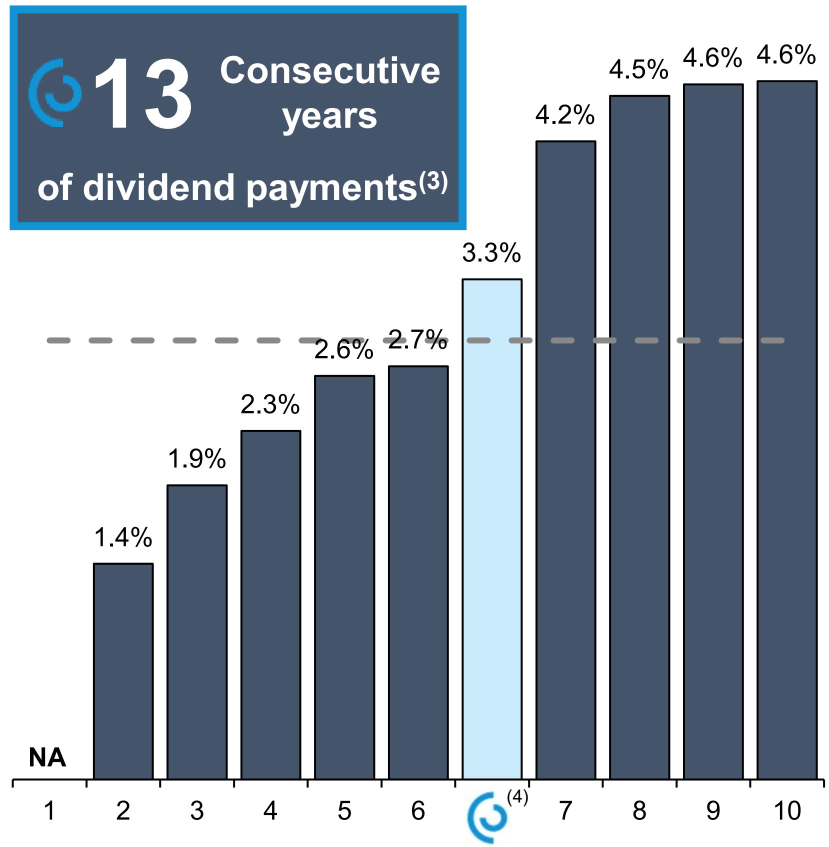
- **$0.12 / share per quarter**

Priority **#2**

$150 MM Buyback Authorization[1]:

- **~$30 MM exercised to date – 20% of authorized**
- **Weighted average share buyback price of $10.07**

Fixed Dividend Yield Comparison[2]



Note: Any payment of future dividends is subject to Board approval and other factors.

(1) Two-year term implemented on 3/4/24.

(2) Public company information based on latest filings. Excludes buybacks and variable dividends. Market data as of 2/7/25. Peers include BTE, CHRD, CIVI, CRC, MGY, MTDR, MUR, NOG, SM and VTLE.

(3) Represents Crescent and its predecessors.

(4) Assumes $0.12 per share quarterly CRGY dividend. Dividend yield based on CRGY share price of $14.66 as of 2/7/25.

Appendix

2025 Outlook: Flexible Capital Allocation and Significant Free Cash Flow Generation

Guidance

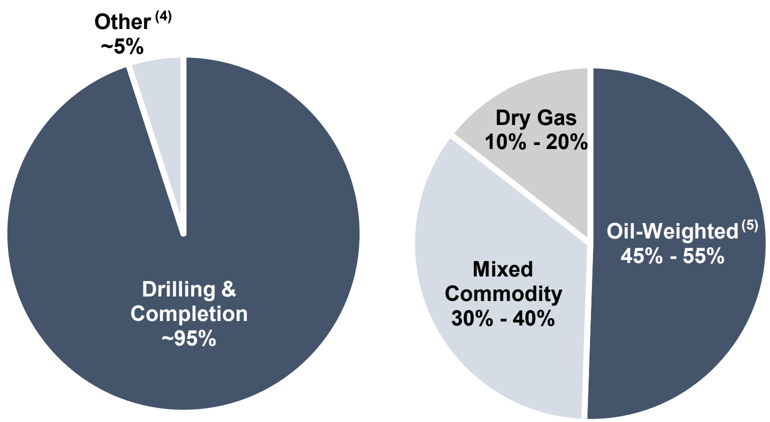
($70 / Bbl WTI and $3.00 / MMbtu Henry Hub)

	Full Year 2025
Total Production (Mboe/d)	254 – 264
***% Oil** (%)*	*41% – 40%*
***% Gas** (%)*	*41% – 43%*
Realized Prices (Oil % of WTI / Gas % of HHUB)	Mid ~90% / Low - Mid ~80%
Capital Expenditures (Ex. Acquisitions) ($MM)	$925 – $1,025
Adj. Opex Ex. Prod. & Other Taxes ($/Boe)[1][2]	$12.25 – $13.25
Production Taxes (% of Commodity Revenue)	6.0% – 7.0%
Adj. Recurring Cash G&A ($/boe)[3]	$1.20 – $1.30
Cash Taxes (% of Adj. EBITDAX)	2.0% – 5.0%

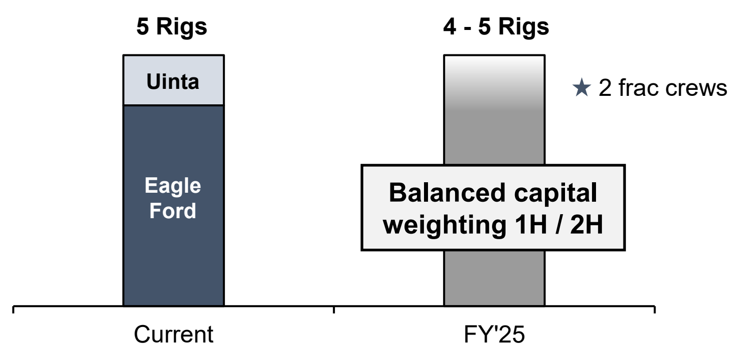
Capital Expenditures

By Type

By Commodity



Activity Detail

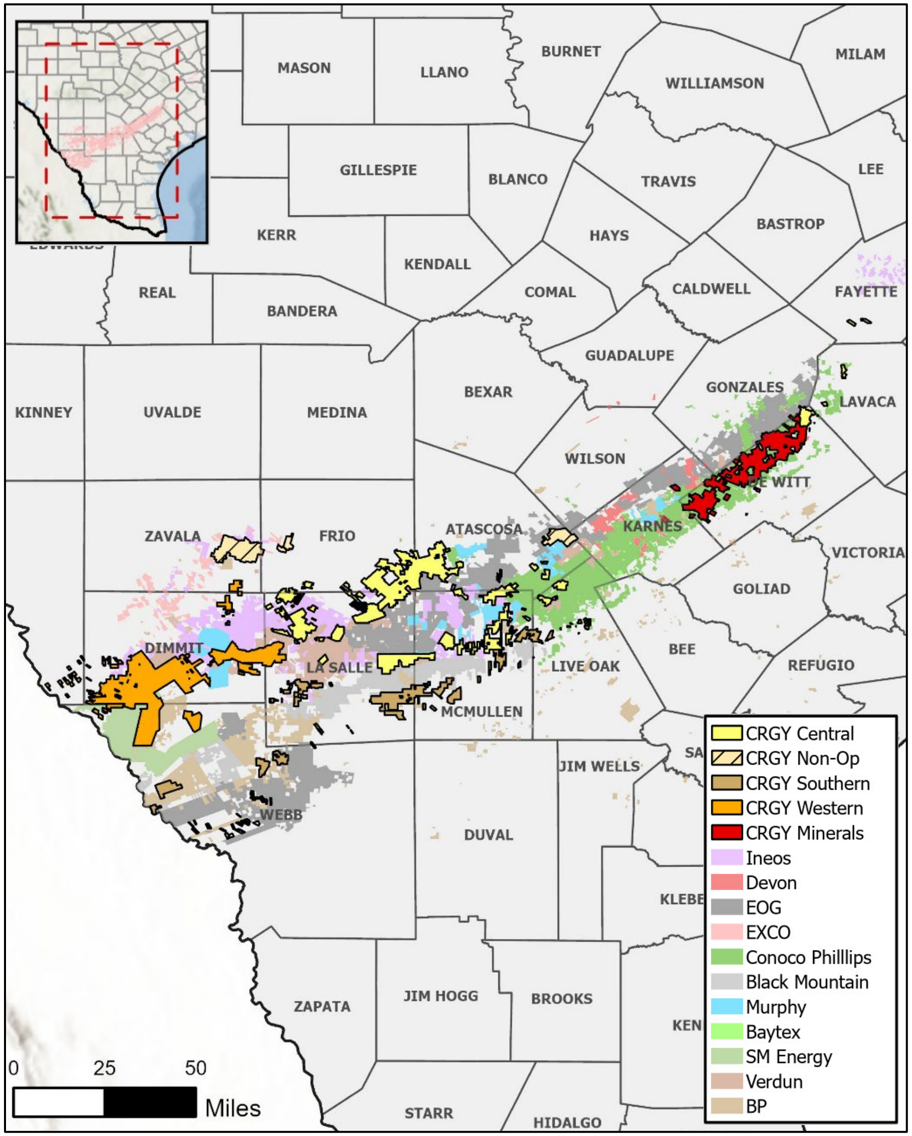


(1) Includes certain costs that are indexed to commodity prices, such as CO_2 purchase costs related to a Wyoming CO2 flood asset, and certain gathering and transportation expenses. These commodity indexed operating expenses move in tandem with oil commodity prices and as oil price increases, higher commodity linked operating costs are offset by higher realizations.
(2) Non-GAAP measure. Adjusted operating expense excluding production and other taxes includes lease operating expense, workover expense, asset operating expense, gathering, transportation and marketing and midstream and other revenue net of expense.
(3) Non-GAAP measure. G&A Expense less noncash equity-based compensation less transaction and nonrecurring expenses plus the pro rata share of Manager Compensation attributable to Class B shareholders (redeemable noncontrolling interests).
(4) Other capital expenditures includes midstream and field development, sustainability initiatives and other Non-D&C related capital.
(5) Oil-Weighted includes Central EGF oil and Uinta development capital.

Eagle Ford Asset Detail:
Premier Position with Attractive Commodity Diversification

Asset Detail

	Operated			
	Central	**Southern**	**Western**	**Non-Op**
Net Acres	~240k	~100k	~165k	~33k
Counties	Live Oak, Atascosa, McMullen, La Salle, DeWitt, Lavaca, Frio	Webb, La Salle, McMullen, Live Oak	Dimmit, Webb, Maverick, La Salle	Zavala, Frio, Atascosa, Webb
Avg. WI / NRI(1)	~83% / ~63%	~85% / ~63%	~60% / ~45%	~38% / ~30%
% Oil	~75%	~0%	~45%	~80%
Current Rigs		4		0 – 1
Gross Locations(2)				
Low-Risk	~465	~135	~300	~75
Total	~665	~200	~515	~85
DC&F $ / ft(3)	~$800	~$975	~$775	~$930
'25 Avg. Lateral	~11,000'	~11,600'	~9,800'	~11,000'
Takeaway	Premium Gulf Coast pricing (MEH)			

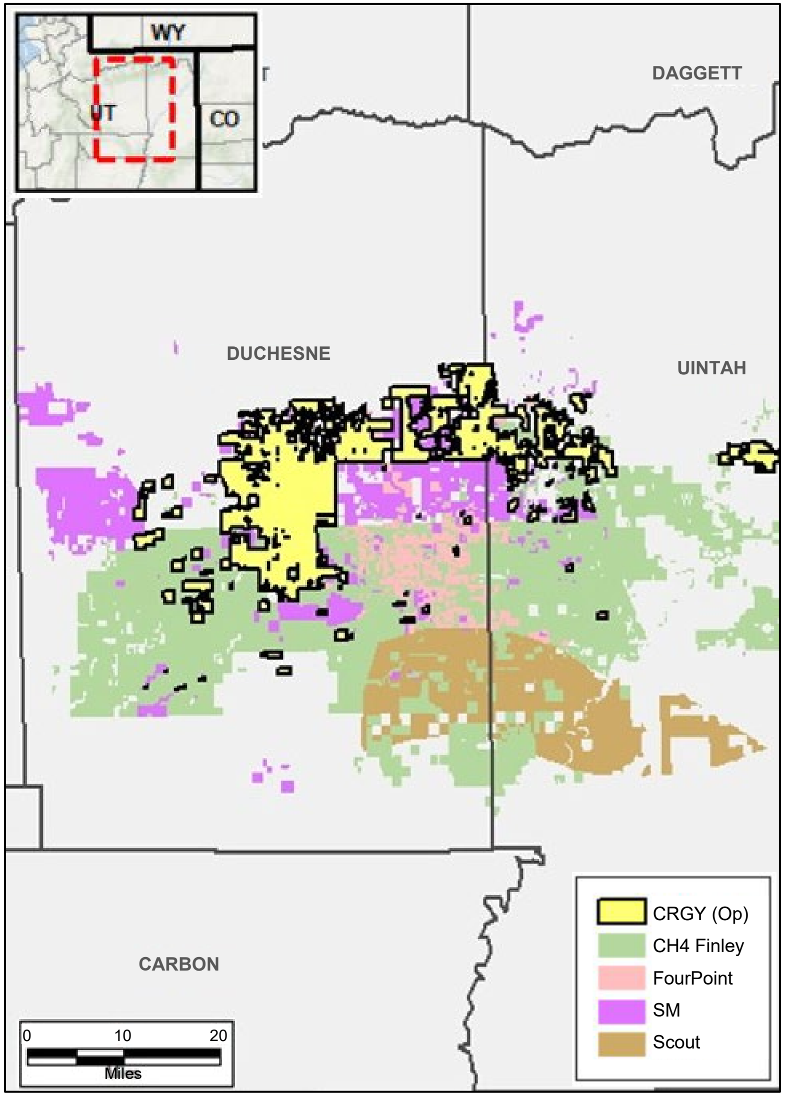


Note: Map based on Enverus operator shapefiles. Location counts as of year end 2024.
(1) Western Eagle Ford % oil and working interest on remaining development is slightly higher than developed acreage.
(2) Low-risk locations represent technical PUDs from our YE reserves (PUD locations + locations that would be PUDs if not for the 5 year development timing rule). Total represents 3P locations.
(3) DC&F costs represent current expectations by area.

Uinta Asset Detail:
HBP Asset Base with Substantial Stacked Resource Opportunity

Asset Detail

	Uinta
Net Acres	~145k
Counties	Duchesne & Uintah
Avg. WI / NRI	~85% / ~70%
% Oil(1)	~80%
Current Rigs	1
Gross Locations(2)	~650
DC&F $ / ft	~$950
’25 Avg. Lateral	~9,900’
Takeaway	High-value crude with secured capacity



Inventory Upside

Current CRGY inventory estimates only include a portion of substantial resource opportunity

Uinta Formations	Peer Activity	CRGY
Garden Gulch	✓	
Upper Douglas Creek	✓	
Middle Douglas Creek	✓	
Lower Douglas Creek	✓	
Black Shale	✓	
Castle Peak	✓	✓
Castle Peak Lime	✓	
Uteland Butte A	✓	✓
Uteland Butte B	✓	✓
Uteland Butte C	✓	✓
Upper Wasatch 5	✓	✓
Lower Wasatch 5	✓	✓
Wasatch 4	✓	
Wasatch 3	✓	
Wasatch 2	-	
Wasatch 1	-	
Upper Flagstaff	✓	
Middle Flagstaff	-	
Lower Flagstaff	-	

Note: Map based on Enverus operator shapefiles. Location counts as of year end 2024.
(1) Future development inventory is ~80% oil.
(2) Gross locations based on delineated formations only.

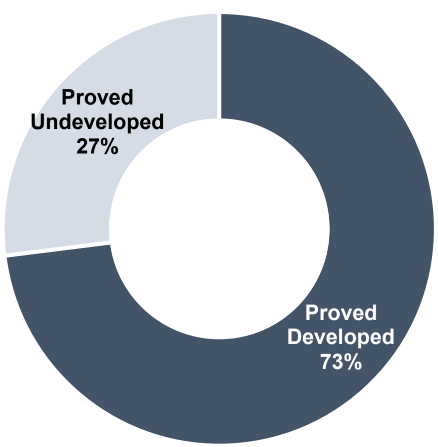
Crescent Energy Reserves Summary

~65% Liquids and ~73% Proved Developed

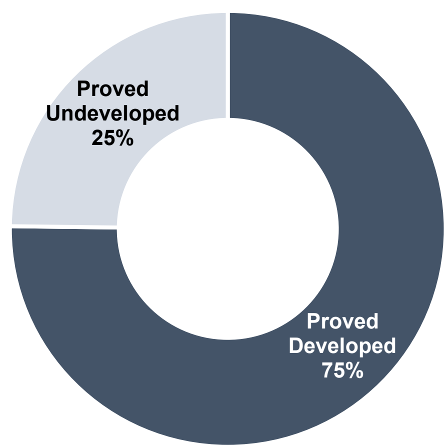
YE 2024 Proved Reserves Summary

Reserve Category	Oil (MMbbl)	Gas (Bcf)	NGL (MMbbl)	Total (MMboe)	PV-10 ($MM) SEC(1)(2)
Proved Developed	232	1,384	117	579	$6,016
Proved Undeveloped	126	278	41	214	1,984
Total Proved Reserves	**358**	**1,662**	**158**	**793**	**$8,000**

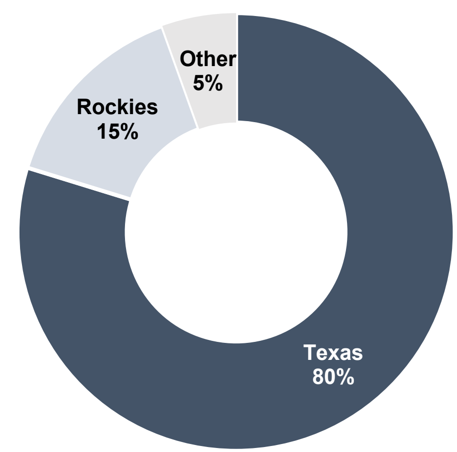
Reserves By Category



Total Proved PV-10(1)(2) By Category



Total Proved PV-10(1)(2) By Area



Note: Pro forma for Ridgemar transaction that closed on January 31, 2025.

(1) PV-10 is a non-GAAP financial measure. For a reconciliation to the comparable GAAP measure, see Appendix.

(2) Based on YE'24 reserves. YE'24 SEC pricing calculated using the simple average of the first-of-the month commodity prices for 2024, adjusted for location and quality differentials, with consideration of known contractual price changes. The average benchmark prices per unit, before location and quality differential adjustments, used to calculate the related reserve category was $75.48 / bbl for oil and $2.13 / MMbtu for gas.

Hedge Position: Liquids

	Q1 2025	Q2 2025	Q3 2025(1)	Q4 2025(1)	FY 2026(2)	FY 2027(3)
NYMEX WTI (Bbls, $/Bbl)						
Swaps						
Total Volumes	3,799,000	3,903,900	3,946,800	3,854,800	**7,038,550**	**3,650,000**
Total Daily Volumes	42,211	42,900	42,900	41,900	**19,284**	**10,000**
WA Swap Price	$70.45	$70.48	$70.43	$70.30	**$71.67**	**$75.00**
Collars						
Total Volumes	1,498,500	1,501,500	1,288,000	1,288,000	**1,003,000**	--
Total Daily Volumes	16,650	16,500	14,000	14,000	**2,748**	--
WA Long Put Price	$62.59	$62.09	$62.32	$62.32	**$64.73**	--
WA Short Call Price	$78.82	$78.49	$79.61	$79.61	**$74.78**	--
ICE Brent (Bbls, $/Bbl)						
Collars						
Total Volumes	90,000	91,000	92,000	92,000	--	--
Total Daily Volumes	1,000	1,000	1,000	1,000	--	--
WA Long Put Price	$65.00	$65.00	$65.00	$65.00	--	--
WA Short Call Price	$91.61	$91.61	$91.61	$91.61	--	--
MEH Differential (Bbls, $/Bbl)						
Swaps						
Total Volumes	4,317,000	4,459,000	4,232,000	4,232,000	**3,831,000**	--
Total Daily Volumes	47,967	49,000	46,000	46,000	**10,500**	--
WA Swap Price	$1.62	$1.62	$1.62	$1.62	**$1.85**	--
CMA Roll (Bbls, $/Bbl)						
Swaps						
Total Volumes	3,991,500	4,459,000	4,232,000	4,232,000	**1,825,000**	--
Total Daily Volumes	44,350	49,000	46,000	46,000	**5,000**	--
WA Swap Price	$0.37	$0.39	$0.36	$0.36	**$0.20**	--
Total NGLs (Bbls, $/Bbl)						
Swaps						
Total Volumes	360,000	364,000	368,000	368,000	--	--
Total Daily Volumes	4,000	4,000	4,000	4,000	--	--
WA Swap Price	$23.88	$23.88	$23.88	$23.88	--	--

Note: Hedge position as of February 24, 2025. Includes hedge contracts beginning January 1, 2025.

(1) The 2H 2025 WTI swap contracts include 2,000 bbl/d of swaptions that may be extended at the option of the counterparty.

(2) The FY 2026 WTI swap contracts include 9,500 bbl/d of swaptions and collars that may be extended at the option of the counterparty.

(3) The FY 2027 WTI swap contracts include 10,000 bbl/d of swaptions that may be extended at the option of the counterparty.

Hedge Position: Gas

	Q1 2025	Q2 2025	Q3 2025	Q4 2025	FY 2026	FY 2027[(1)]
NYMEX Henry Hub (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	14,580,000	14,742,000	17,204,000	13,994,000	**85,545,000**	**18,250,000**
Total Daily Volumes	162,000	162,000	187,000	152,109	**234,370**	**50,000**
WA Swap Price	$4.21	$3.70	$3.83	$4.13	**$4.03**	**$4.19**
Collars						
Total Volumes	19,620,000	19,565,000	15,732,000	19,092,000	**40,100,000**	--
Total Daily Volumes	218,000	215,000	171,000	207,522	**109,863**	--
WA Long Put Price	$3.26	$3.06	$3.03	$3.09	**$3.02**	--
WA Short Call Price	$5.85	$5.52	$5.91	$5.70	**$4.65**	--
HSC Differential Swaps (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	23,400,000	23,660,000	22,080,000	22,690,000	**76,600,000**	**36,500,000**
Total Daily Volumes	260,000	260,000	240,000	246,630	**209,863**	**100,000**
WA Swap Price	($0.24)	($0.31)	($0.29)	($0.31)	**($0.44)**	**($0.38)**
NGPL TXOK Differential Swaps (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	3,600,000	3,640,000	3,680,000	3,680,000	--	--
Total Daily Volumes	40,000	40,000	40,000	40,000	--	--
WA Swap Price	($0.37)	($0.37)	($0.37)	($0.37)	--	--
Transco St 85 (Z4) Differential Swaps (MMBtu, $/MMBtu)						
Swaps						
Total Volumes	1,242,000	1,255,800	1,269,600	1,269,600	--	--
Total Daily Volumes	13,800	13,800	13,800	13,800	--	--
WA Swap Price	$0.32	$0.32	$0.32	$0.32	--	--

Note: Hedge position as of February 24, 2025. Includes hedge contracts beginning January 1, 2025.
(1) The FY 2027 NYMEX Henry Hub swap contracts include 50,000 mmbtu/d of swaptions that may be extended at the option of the counterparty.

Per Unit Performance

	Year ended	For the three months ended		
	December 31, 2024	December 31, 2024	December 31, 2023	September 30, 2024
Average daily net sales volumes:				
Oil (Mbbls/d)	82	98	71	86
Natural gas (MMcf/d)	501	671	386	554
NGLs (Mbbls/d)	36	45	30	40
Total (Mboe/d)	201	255	165	219
Average realized prices, before effects of derivative settlements:				
Oil ($/Bbl)	$71.14	$67.51	$74.07	$69.19
Natural gas ($/Mcf)	1.91	2.27	2.39	1.55
NGLs ($/Bbl)	24.10	23.08	22.50	23.53
Total ($/Boe)	37.99	35.99	41.39	35.50
Average realized prices, after effects of derivative settlements:				
Oil ($/Bbl)	$67.38	$67.54	$67.06	$66.93
Natural gas ($/Mcf)	2.33	2.39	2.46	2.00
NGLs ($/Bbl)	24.05	22.91	22.50	23.56
Total ($/Boe)[1]	37.50	36.30	38.55	35.76
Expense (per Boe)				
Operating expense	$17.36	$15.08	$20.47	$16.23
Depreciation, depletion and amortization	12.89	13.18	12.07	12.50
General and administrative expense	4.57	3.70	2.29	7.93
Non-GAAP and other expense (per Boe)				
Adjusted operating expense, excluding production and other taxes[2][3]	$13.33	$11.37	$15.38	$12.57
Production and other taxes	2.21	2.38	3.08	2.15
Adjusted Recurring Cash G&A[2]	1.26	1.28	1.47	1.13

(1) The realized price presented does not include the $34.5 million and $12.5 million received from and paid for the settlement of acquired derivative contracts for the three months ended December 31, 2024, and December 31, 2023, respectively. Total average realized prices, after effects of derivatives settlements, would have been $37.77/Boe and $37.73/Boe for the three months ended December 31, 2024, and December 31, 2023, respectively.

(2) Non-GAAP financial measure. Please see "Reconciliation of Non-GAAP Measures" for discussion and reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with U.S. generally accepted accounting principles ("GAAP").

(3) Adjusted operating expense excluding production and other taxes includes lease operating expense, workover expense, asset operating expense, gathering, transportation and marketing and midstream and other revenue net of expense.

Adjusted EBITDAX & Levered Free Cash Flow

Adjusted EBITDAX & Levered Free Cash Flow

Crescent defines Adjusted EBITDAX as net income (loss) before interest expense, loss from extinguishment of debt, income tax expense (benefit), depreciation, depletion and amortization, exploration expense, non-cash gain (loss) on derivatives, equity-based compensation, (gain) loss on sale of assets, other (income) expense and transaction and nonrecurring expenses. Additionally, we further subtract certain redeemable noncontrolling interest distributions made by OpCo and settlement of acquired derivative contracts. We include "Certain-redeemable noncontrolling interest distributions made by OpCo" to reflect Manager Compensation as if 100% of OpCo were owned and managed by the Company, to reflect consistent earnings and liquidity measures not impacted by the amount of OpCo's ownership under management.

Adjusted EBITDAX is not a measure of performance as determined by GAAP. We believe Adjusted EBITDAX is a useful performance measure because it allows for an effective evaluation of our operating performance when compared against our peers, without regard to our financing methods, corporate form or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP, of which such measure is the most comparable GAAP measure. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax burden, as well as the historic costs of depreciable assets, none of which are reflected in Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by unusual or nonrecurring items. Our computations of Adjusted EBITDAX may not be identical to other similarly titled measures of other companies. In addition, the Revolving Credit Facility and Senior Notes include a calculation of Adjusted EBITDAX for purposes of covenant compliance.

Crescent defines Levered Free Cash Flow as Adjusted EBITDAX less interest expense, excluding non-cash amortization of deferred financing costs, discounts, and premiums, loss from extinguishment of debt, excluding non-cash write-off of deferred financing costs, discounts, and premiums and SilverBow merger transaction related costs, current income tax benefit (expense), tax-related redeemable noncontrolling interest distributions made by OpCo and development of oil and natural gas properties. Levered Free Cash Flow does not take into account amounts incurred on acquisitions. Levered Free Cash Flow is not a measure of liquidity as determined by GAAP. Levered Free Cash Flow is a supplemental non-GAAP liquidity measure that is used by our management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Levered Free Cash Flow is a useful liquidity measure because it allows for an effective evaluation of our operating and financial performance and the ability of our operations to generate cash flow that is available to reduce leverage or distribute to our equity holders. Levered Free Cash Flow should not be considered as an alternative to, or more meaningful than, Net cash flow provided by operating activities as determined in accordance with GAAP, of which such measure is the most comparable GAAP measure, or as an indicator of actual liquidity, operating performance or investing activities. Our computations of Levered Free Cash Flow may not be comparable to other similarly titled measures of other companies.

The following table reconciles Adjusted EBITDAX (non-GAAP) and Levered Free Cash Flow (non-GAAP) to net income (loss), the most directly comparable financial measure calculated in accordance with GAAP:

Adjusted EBITDAX & Levered Free Cash Flow (Cont'd)

	Three Months Ended December 31,		Year Ended December 31,	
	2024	2023	2024	2023
	(in thousands)		(in thousands)	
Net income (loss)	($169,945)	$140,008	($137,683)	$321,991
Adjustments to reconcile to Adjusted EBITDAX:				
Interest expense	69,378	43,159	216,263	145,807
Loss from extinguishment of debt	—	—	59,095	—
Income tax expense (benefit)	(36,750)	18,328	(31,072)	23,227
Depreciation, depletion and amortization	309,036	182,903	949,480	675,782
Exploration expense	1,833	7,787	16,591	9,328
Non-cash (gain) loss on derivatives	116,916	(278,150)	78,494	(320,714)
Impairment expense	161,542	153,495	161,542	153.495
Equity-based compensation expense	54,433	18,288	193,481	82,936
(Gain) loss on sale of assets	(9,993)	—	(29,430)	—
Other (income) expense	645	1,489	(1,760)	282
Certain RNCI Distributions made by OpCo	(4,525)	(6,798)	(19,963)	(30,563)
Transaction and nonrecurring expenses	7,711	8,444	82,484	22,632
Settlement of acquired derivative contracts[1]	34,496	(12,478)	60,787	(61,455)
Adjusted EBITDAX (non-GAAP)	$534,777	$276,475	$1,598,309	$1,022,748
Adjustments to reconcile to Levered Free Cash Flow:				
Interest expense, excluding non-cash amortization of deferred financing costs, discounts, and premiums	(65,782)	(39,508)	(202,886)	(132,981)
Loss from extinguishment of debt, excluding non-cash write-off of deferred financing costs, discounts, premiums and SilverBow Merger transaction related costs	—	—	(14,817)	—
Current income tax benefit (expense)	11,125	417	(4,782)	(494)
Tax-related RNCI Contributions (Distributions) made by OpCo	(118)	(862)	(458)	(753)
Development of oil and natural gas properties	(220,580)	(134,071)	(745,198)	(578,316)
Levered Free Cash Flow (non-GAAP)	$259,422	$102,451	$630,168	$310,204

(1) *Transaction and nonrecurring expenses of $7.7 million for the three months ended December 31, 2024, were primarily related to our SilverBow merger costs, capital markets transactions and integration expenses. Transaction and nonrecurring expenses of $8.4 million for the three months ended December 31, 2023, were primarily related to our Western Eagle Ford Acquisitions and system integration expenses. Transaction and nonrecurring expenses of $82.5 million during the year ended December 31, 2024, were primarily related to the SilverBow Merger, capital markets transactions and integration expenses. Transaction and nonrecurring expenses of $22.6 million for the year ended December 31, 2023, were primarily related to the Western Eagle Ford Acquisitions and system integration expenses.*

Net LTM Leverage & PV-10 Reconciliation

Net LTM Leverage

Crescent defines Net LTM Leverage as the ratio of consolidated total debt to consolidated Adjusted EBITDAX as calculated under the credit agreement (the "Credit Agreement") governing Crescent's Revolving Credit Facility. Management believes Net LTM Leverage is a useful measurement because it takes into account the impact of acquisitions. For purposes of the Credit Agreement, (i) consolidated total debt is calculated as total principal amount of Senior Notes, net of unamortized discount, premium and issuance costs, plus borrowings on our Revolving Credit Facility and unreimbursed drawings under letters of credit, less cash and cash equivalents and (ii) consolidated Adjusted EBITDAX includes certain adjustments to account for EBITDAX contributions associated with acquisitions the Company has closed within the last twelve months. Adjusted EBITDAX is a non-GAAP financial measure.

	December 31, 2024
	(in millions)
Total debt[1]	$3,049
Less: cash and cash equivalents	(133)
Net debt for credit purposes	$2,916
LTM Adjusted EBITDAX for Leverage Ratio	$2,066
Net LTM Leverage	1.4x

Standardized Measure Reconciliation to PV-10[2]

(in millions)	**For the year ended December 31, 2024**
Standardized measure of discounted future net cash flows	$5,704
Present value of future income taxes discounted at 10%	755
Total Proved PV-10 at SEC Pricing	$6,459

(1) Includes $50.7 million of unamortized discount, premium and issuance costs.
(2) Excludes Ridgemar transaction that closed on January 31, 2025.

Adjusted Recurring Cash G&A

Adjusted Recurring Cash G&A

Crescent defines Adjusted Recurring Cash G&A as general and administrative expense, excluding equity-based compensation and transaction and nonrecurring expenses, and including cash distributions initiated by Manager Compensation. We include "Certain RNCI distributions made by OpCo" to reflect Manager Compensation as if 100% of OpCo were owned and managed by the Company, to reflect consistent earnings and liquidity measures not impacted by the amount of OpCo's ownership under management. Management believes Adjusted Recurring Cash G&A is a useful performance measure because it excludes transaction and nonrecurring expenses and equity-based compensation and includes Manager Compensation as if 100% of OpCo were owned and managed by the Company to reflect consistent measures not impacted by the amount of OpCo's ownership under management, facilitating the ability for investors to compare Crescent's cash G&A expense against peer companies. As discussed elsewhere, these adjustments are made to Adjusted EBITDAX and Levered Free Cash Flow for historical periods and periods for which we present guidance.

	Three Months Ended December 31,		Year Ended December 31,	
	2024	2023	2024	2023
	(in thousands)		(in thousands)	
General and administrative expense	$86,687	$34,683	$336,219	$140,918
Less: Equity-based compensation expense	(54,433)	(18,288)	(193,481)	(82,936)
Less: Transaction and nonrecurring expenses[1]	(6,667)	(973)	(69,881)	(6,033)
Plus: Certain RNCI Distributions made by OpCo	4,525	6,798	19,963	30,563
Adjusted Recurring Cash G&A	$30,112	$22,220	$92,820	$82,512

(1) *Transaction and nonrecurring expenses (G&A) of $6.7 million and $69.9 million for the three months and year ended December 31, 2024, were primarily related to our SilverBow merger costs, capital markets transactions and integration expenses, respectively. Transaction and nonrecurring expenses of $1.0 million and $6.0 million for the three months and year ended December 31, 2023, were primarily related to system integration expenses, respectively.*

Stay Connected.

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