Investor Presentation

March 2024

Forward Looking Statement

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Unit Corporation (the Company) expects, believes or anticipates will or may occur in the future are forward-looking statements. The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “should,” “would,” “could,” or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company’s drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management’s expectations and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include risks relating to financial performance and results, current economic conditions and resulting capital restraints, prices and demand for oil and natural gas, availability of drilling equipment and personnel, availability of sufficient capital to execute the Company’s business plan, the Company’s ability to replace reserves and efficiently develop and exploit its current reserves and other important factors that could cause actual results to differ materially from those projected and other risks disclosed under “Risk Factors” in the Company’s most recent Annual Report and Quarterly Reports filed thereafter. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law. This presentation may contain certain terms, such as locations and estimated ultimate recovery (“EUR”) and other similar terms that describe estimates of potential wells and potentially recoverable hydrocarbons that SEC rules prohibit from being included in filings with the SEC. These estimates are by their nature more speculative than estimates of proved, probable and possible reserves and may not constitute “reserves” within the meaning of SEC rules and accordingly, are subject to substantially greater risk of being actually realized. These estimates are based on the Company’s existing models and internal estimates. Actual quantities that may be ultimately recovered from the Company’s interests will differ substantially. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of unproved reserves may change significantly as development of the Company’s core assets provide additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation may contain financial measures that have not been prepared in accordance with U.S. Generally Accepted Accounting Principles (“non-GAAP financial measures”) including PV-10 reserve values and certain operating measures such as Adjusted EBITDA. The non-GAAP financial measures should not be considered a substitute for financial measures prepared in accordance with U.S. Generally Accepted Accounting Principles (“GAAP”). We urge you to review the reconciliations of the non-GAAP financial measures to GAAP financial measures in the appendices.

Investment Highlights

- Established track record of returning value to shareholders
  - $37.50 per share of dividends paid in 2023
  - 2.47 million shares repurchased since 2020 bankruptcy emergence
  - **2024 Quarterly Dividends of $1.25 per share**
- Strong balance sheet as of December 31, 2023
  - $61 million of net cash & cash equivalents
  - No long-term debt
- Reserves as of December 31, 2023[1]
  - $237 million based on the SEC standardized measure
  - PDP PV-10:
    - $249 million based on SEC pricing
    - $248 million based on forward strip pricing
- All 14 BOSS rigs contracted and operating in the Permian Basin
- Substantial remaining tax shield of $244 million of NOL's as of December 31, 2023
- Final payment of $8 million from sale of Superior to be received in April 2024

[1] See Appendix 2 for reconciliation of reserve values to standardized measure

2023 Consolidated Financial Highlights

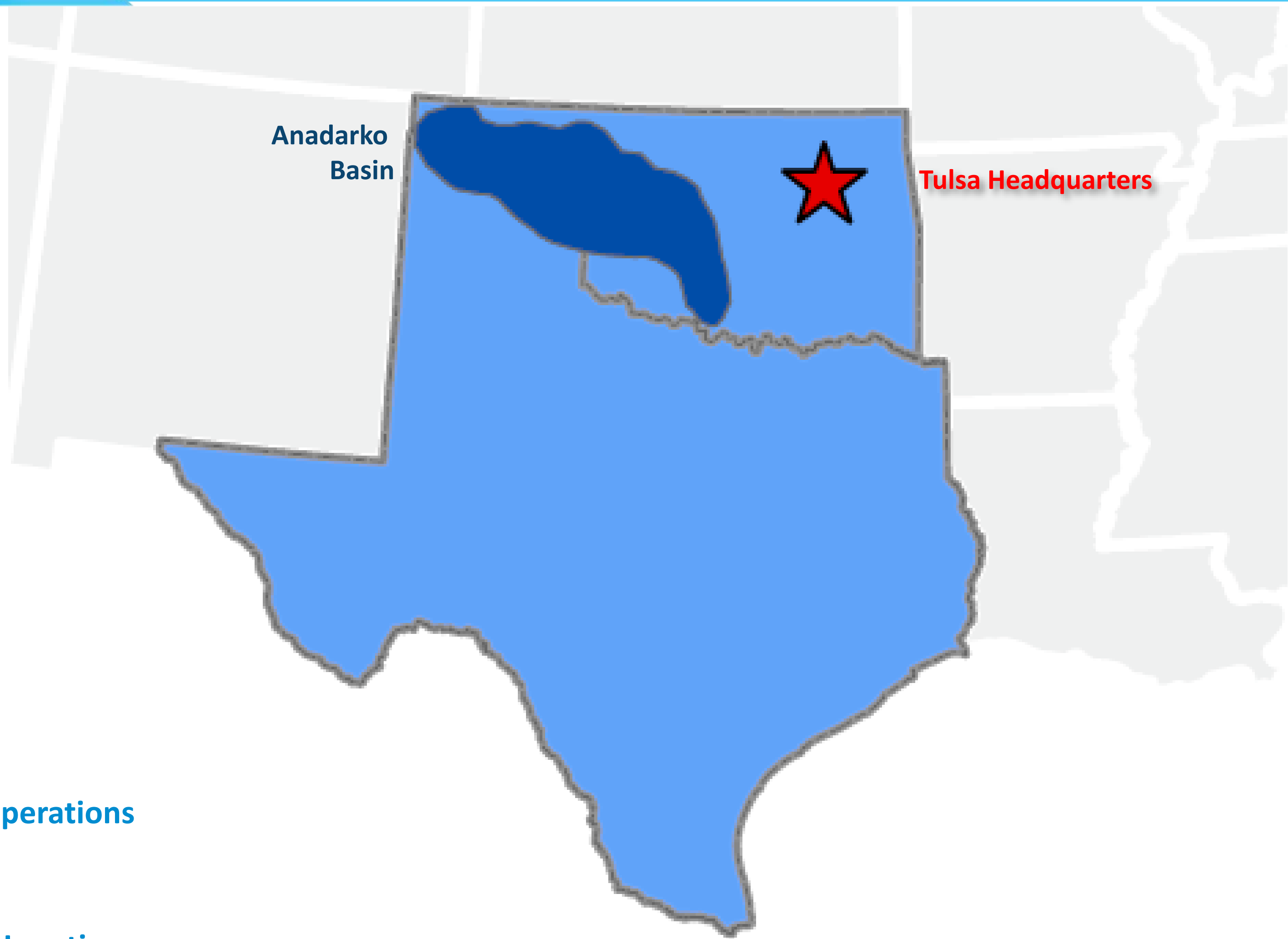
	1Q23 [1]	2Q23	3Q23	4Q23	FY2023
	(in thousands, except per share amounts)				
Revenues:					
Oil and natural gas	$ 48,026	$ 31,176	$ 35,205	$ 31,830	$ 146,237
Contract drilling	$ 45,903	$ 47,405	$ 44,951	$ 42,797	$ 181,056
Gas gathering and processing	$ -	$ -	$ -	$ -	$ -
Total revenues	$ 93,929	$ 78,581	$ 80,156	$ 74,627	$ 327,293
Net income attributable to Unit Corporation	$ 134,650	$ 28,017	$ 28,835	$ 57,437	$ 248,939
Basic earnings per share	$ 13.93	$ 2.90	$ 2.98	$ 5.89	$ 25.68
Diluted earnings per share	$ 13.75	$ 2.86	$ 2.94	$ 5.79	$ 25.32
Adjusted EBITDA [1]	$ 51,143	$ 32,782	$ 30,629	$ 25,161	$ 139,715
Capital expenditures	$ 1,606	$ 3,774	$ 6,195	$ 6,484	$ 18,059

[1] See Appendix 1 for a description of Adjusted EBITDA and reconciliation to net income attributable to Unit Corporation

Unit Petroleum Company (UPC) Summary

- Efficient, low-cost production and modest decline in PDP reserves
- Substantial position of ~147,500 net acres in the Anadarko Basin
- Development strategies:
  - Converting non-producing reserves to producing reserves
  - Evaluating acquisitions of producing properties in core areas
  - High-grading producing properties by selling interests in non-core areas
- Legacy bankruptcy hedges now gone, will hedge opportunistically as deemed appropriate going forward
- Reducing G&A run rate to reflect current smaller footprint and plans

Unit Petroleum Company Operations Footprint



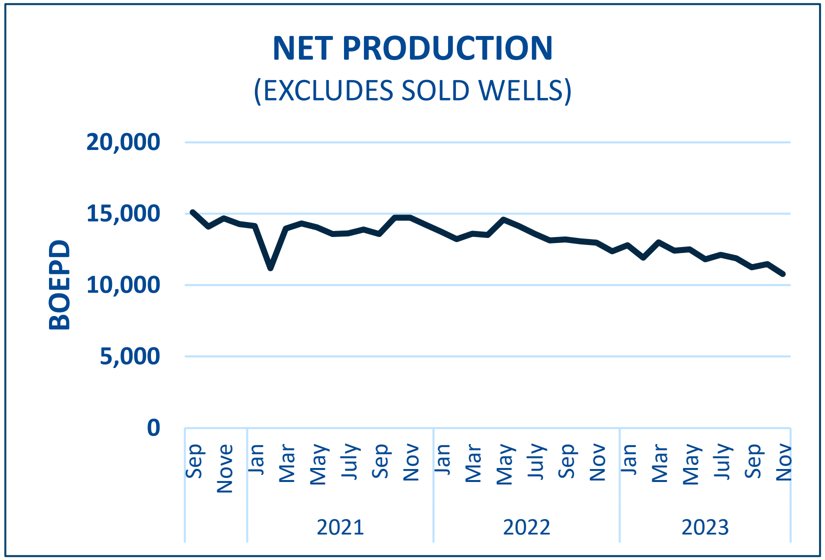
E&P Operations

Office Location

Unit Petroleum Company
2023 Operating and Financial Highlights

	1Q23	2Q23	3Q23	4Q23	YTD
	(In thousands unless otherwise specified)				
Oil and Natural Gas:					
Revenue, before inter-segment eliminations	$ 48,026	$ 31,176	$ 35,205	$ 31,830	$ 146,237
Operating costs, before inter-segment eliminations	$ 17,164	$ 15,224	$ 16,823	$ 16,528	$ 65,739
Average oil price ($/Bbl)	$ 65.96	$ 57.34	$ 60.33	$ 57.12	$ 60.61
Average oil price excluding derivatives ($/Bbl)	$ 73.94	$ 71.62	$ 80.83	$ 76.98	$ 75.57
Average NGLs price ($/Boe)	$ 21.37	$ 14.77	$ 17.79	$ 18.25	$ 18.02
Average NGLs price excluding derivatives ($/Boe)	$ 21.37	$ 14.77	$ 17.79	$ 18.25	$ 18.02
Average natural gas price ($/Mcf)	$ 4.04	$ 1.46	$ 1.75	$ 1.72	$ 2.28
Average natural gas price excluding derivatives ($/Mcf)	$ 3.11	$ 1.32	$ 1.78	$ 2.04	$ 2.07
Oil production (MBbls)	300	250	225	209	984
NGL production (MBbls)	419	428	429	360	1,636
Natural gas production (MMcf)	5,369	5,188	5,185	4,453	20,195
BOE production (MBbls)	1,615	1,543	1,518	1,310	5,986
Capital expenditures, before inter-segment eliminations	$ 1,020	$ 2,928	$ 2,073	$ 685	$ 6,706

Unit Petroleum Company Producing Properties



- ~147,500 net developed acres in Anadarko Basin
- Modest production decline rate
- 4,623 wells (~788 net wells)
- Low water production
- Optimize production and operating costs
- Perform workovers, recompletions or return-to-production to increase production
  - Anticipated workover and maintenance spend of $4 million per year
- Reduce plugging and abandoning liability
  - Current salvaged equipment pricing creates an opportunity for more economic plugging and abandoning of wells
  - Anticipate plugging and abandoning spend of $1 million per year
- Continued focus on environmental impact and safe operations

Unit Petroleum Company Reserves Update

The following table presents the components of the standardized measure of discounted future net cash flows:

	2023 (In thousands)
Future cash inflows	$ 850,979
Future production costs	$ (434,221)
Future development costs	$ (991)
Future income tax expenses	$ (11,714)
Future net cash flows	$ 404,053
10% annual discount for estimated timing of cash flows	$ (166,872)
Standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves	$ 237,181

- As of December 31, 2023:
  - SEC pricing PDP PV-10 value of $249 million[1]
    - $78.22/bbl oil and $2.64/mcf gas based on first-of-month prices
    - 5,046 MBO; 100 BCF; 9,866 MBNGL net reserve volume
    - Future revenue attributed 45% to oil, 27% to NGL and 28% to gas
  - Strip pricing PDP PV-10 value of $248 million[1]
    - $67.75/bbl oil and $3.36/mcf gas based on strip pricing as of 1/2/2024
    - 4,904 MBO; 107 BCF; 10,050 MBNGL net reserve volume using strip pricing
    - Future revenue attributed 36% to oil, 23% to NGL and 41% to gas

[1] See Appendix 2 for a reconciliation to the standardized measure

Unit Petroleum Company
Change in PDP Reserves during 2023

The decrease in estimated quantities of proved developed oil, NGLs, and natural gas reserves during 2023 was primarily due to divestitures, changes in prices, and current year production.

The table below presents estimated quantities of proved developed oil, NGLs, and natural gas reserves and changes in net quantities of proved developed and undeveloped oil, NGLs and natural gas reserves:

	Oil (MBbls)	NGL (Mbbls)	Gas (Mcf)	Total (MBoe)
2023				
Proved developed and undeveloped reserves:				
Beginning of year	7,681	20,132	212,409	63,215
Revision of previous estimates [1]	(735)	(2,763)	(31,052)	(8,673)
Extensions and discoveries	20	24	1,909	362
Infill reserves in existing proved fields	60	26	291	135
Purchases of minerals in place	-	-	-	-
Production	(984)	(1,636)	(20,195)	(5,986)
Sales	(996)	(5,917)	(63,476)	(17,493)
Net proved developed and undeveloped reserves at December 31, 2023	5,046	9,866	99,886	31,560

[1] Revisions of previous estimates decreased primarily due to changes in the unescalated 12-month average product prices which decreased approximately 16% for oil and 58% for natural gas compared to the December 31, 2022 pricing.

Unit Petroleum Company Development Potential

- Potential locations in Red Fork, Cherokee Shale, Marchand, Medrano, Meramec, Woodford and Granite Wash
  - Drill or farm-out high-graded drilling locations
  - Monetize non-core drilling locations
- Anticipate drilling or participating in 1 to 2 net wells per year, with development capital expenditures of approximately $10 to $20 million per year consistent with recent historical practice and dependent upon future market conditions
- Participated in 1.3 net wells during 2023
- Participated in 1.3 net wells during 2022
- Participated in 4.4 net wells during 2021

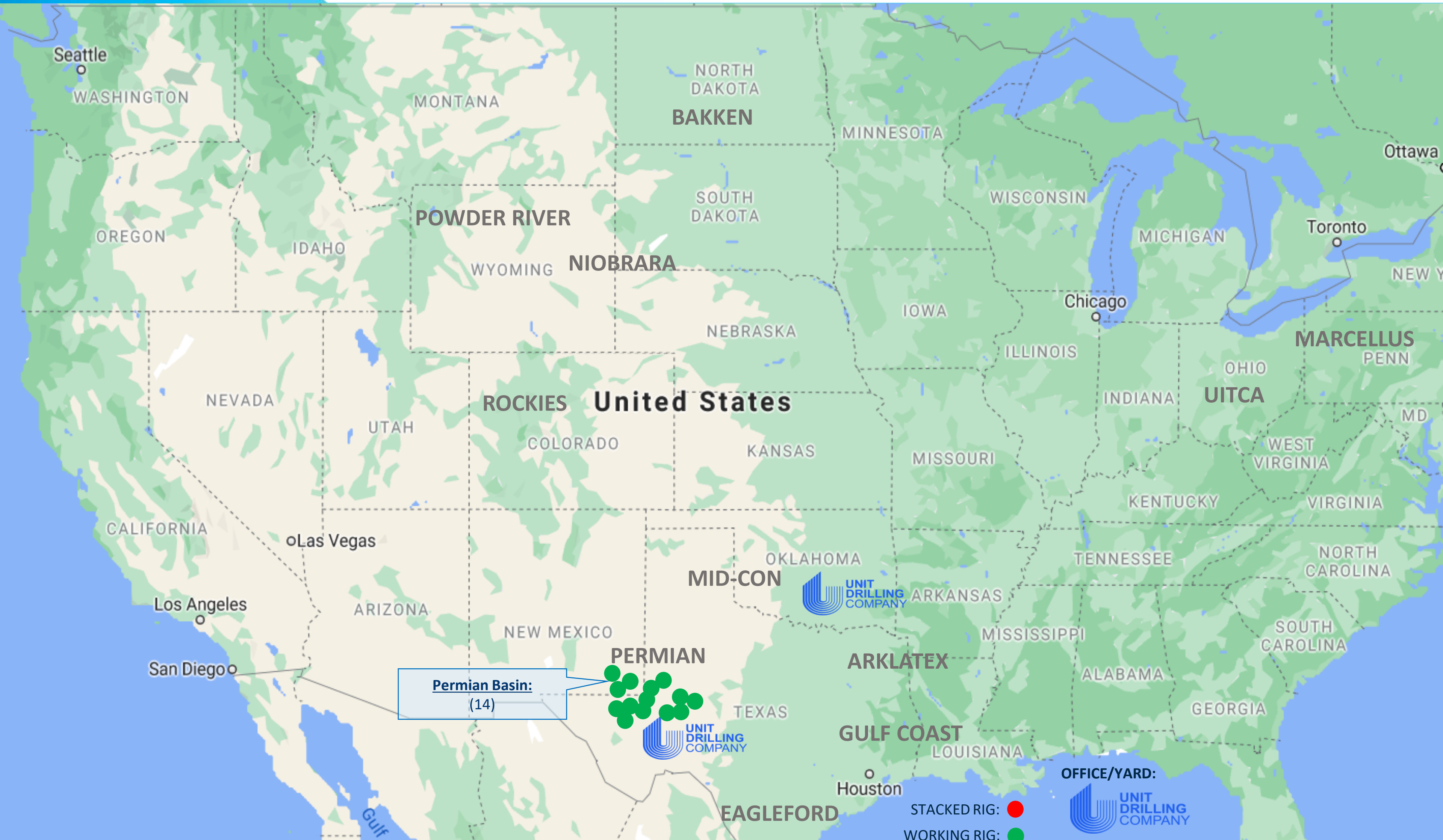
Unit Petroleum Company Divestitures

- Sold interests in 958 wells for $50 million during 2023
    - Sold wells in Texas panhandle and other non-core assets
- Sold interests in 727 wells for $57 million during 2022
    - Sold wells in Gulf Coast area, Oklahoma panhandle, and other non-core assets
- Plugging & Abandonment liability significantly decreased largely due to divestitures
- Will continue to look for opportunities to sell minor interests in outlying areas and concentrate remaining properties in core fields and plays

Unit Drilling Company (UDC) Summary

- 100% pure-play, high-spec drilling fleet of 14 BOSS rigs, working for top-tier operators
- Focused on operating efficiencies with central relocation to core operating region (Texas, New Mexico, and Oklahoma)
- Well balanced contract tenure between term and pad-to-pad contracts
- Estimated contract backlog over 1,300 days
- Average Q4 2023 operating daily rate for BOSS rigs of $31,245
- On-going sales of legacy equipment, with approximately $19 million in proceeds received during 2023
- Committed to the health and safety of our people, and environmental stewardship

Unit Drilling Company Operational Footprint



Unit Drilling Company
2023 Operating and Financial Highlights

	1Q23	2Q23	3Q23	4Q23	YTD
	(In thousands except rig and day amounts, and as otherwise specified)				
Contract Drilling:					
Revenue, before inter-segment eliminations	$ 45,903	$ 47,405	$ 44,951	$ 42,797	$ 181,056
Operating costs, before inter-segment eliminations	$ 26,872	$ 26,882	$ 27,629	$ 26,652	$ 108,035
Total drilling rigs available for use at the end of the period	18	14	14	14	14
Average number of drilling rigs in use	16.8	15.6	14.1	13.9	15.1
Total revenue days	1,513	1,423	1,295	1,280	5,511
Average dayrate on daywork contracts ($/day)	$ 29,592	$ 31,764	$ 32,572	$ 31,245	$ 31,225
Average dayrate on daywork contracts - BOSS Rigs ($/day)	$ 30,845	$ 33,140	$ 32,642	$ 31,245	$ 31,690
Average dayrate on daywork contracts - SCR Rigs ($/day)	$ 24,056	$ 21,087	$ 20,724	$ -	$ 22,944
Capital expenditures	$ 510	$ 820	$ 4,122	$ 5,797	$ 11,249

Unit Drilling Company
High Specification Drilling Contractor

Optimized for Complex Horizontal Wells on Large Drilling Locations

- Multi-direction walking systems designed for large pads
- Increased racking & setback capacity designed for extended reach horizontal drilling programs
- High-Torque 500-Ton Top Drives
- Remote Controlled and Automated Pipe Handling Equipment

Fast Moving Between Drilling Locations

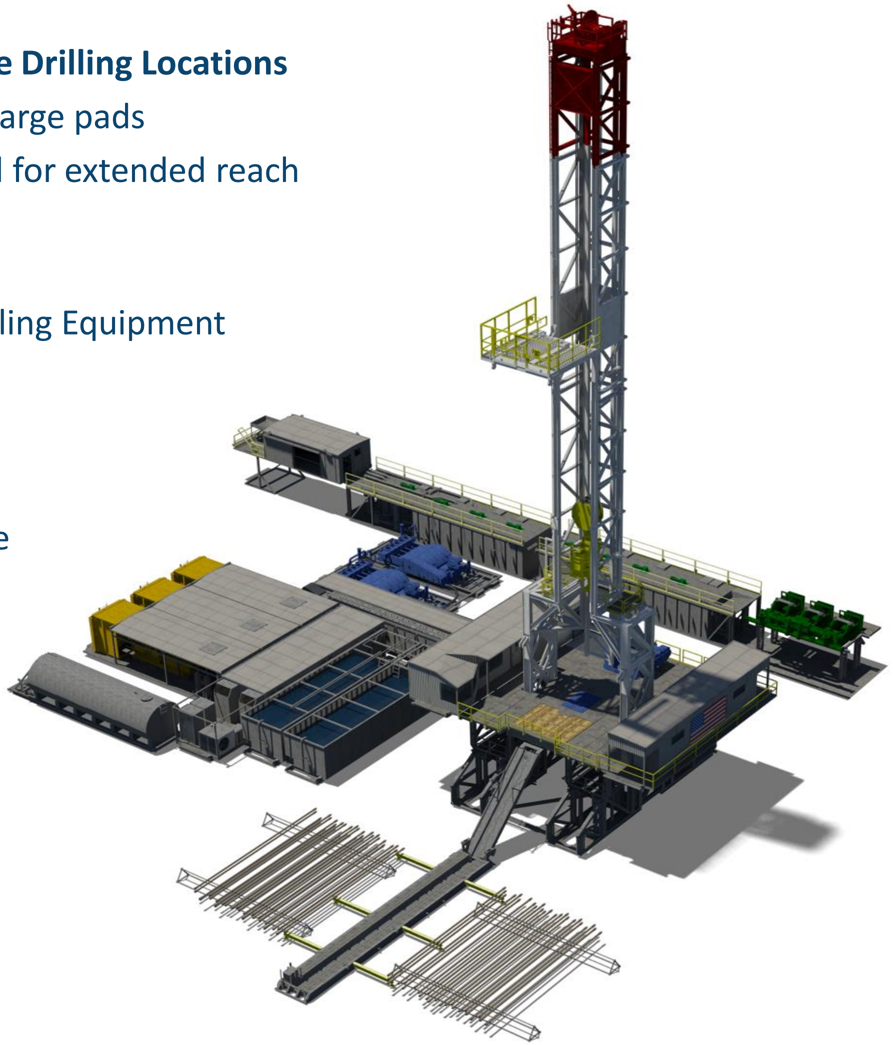
- Box-On-Box Self-Stacking Substructure (BOSS)
- Increased clear-working height of substructure
- 32-34 truck loads

More Hydraulic Mud Pump Horsepower

- (2) 2,200 horsepower quintuplex mud pumps
- Fit for purpose, 7500 psi working pressure

Environmentally Conscious

- Bi-fuel capable engines
- Grid and Battery Power Capable



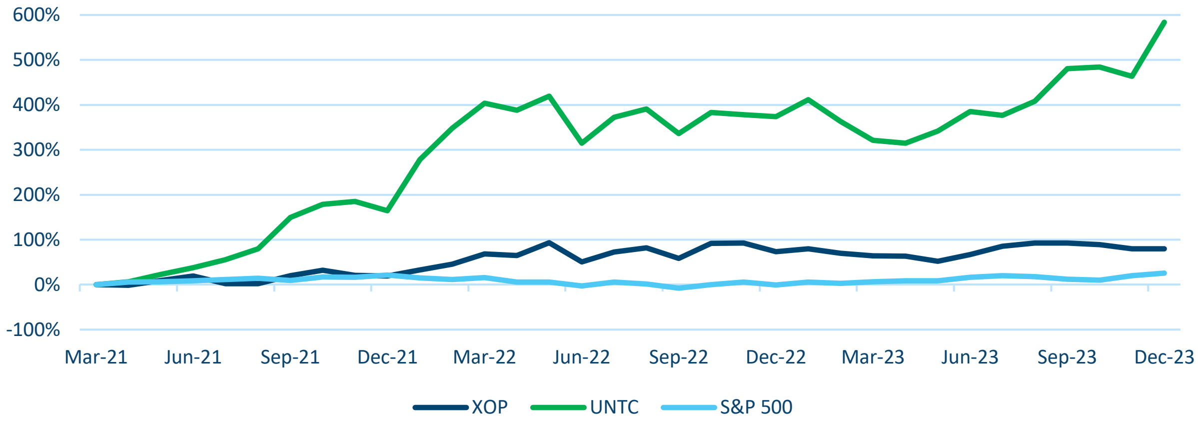
Returning Value to Shareholders

- Total cash dividends of $37.50 per share paid in 2023

- Dividend policy:
  - **2024 quarterly cash dividends of $1.25 per share**
  - Subsequent variable or special dividends to be determined based on future operating cash flows, available cash, working capital, and capital expenditure requirements or opportunities, among other factors

- Repurchased 2,472,392 shares since emergence in September 2020 for $79.3 million at an average cost of $32.09 per share

- Unit's total shareholder return since March 31, 2021 was 584%, compared to 80% for the XOP and 25% for the S&P 500 over the same time frame (Source: CapIQ)



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Appendix 1

Reconciliation of Net Income to Adjusted EBITDA

	1Q23	2Q23	3Q23	4Q23	FY2023
			(in thousands)		
Net income attributable to Unit Corporation	$ 134,650	$ 28,017	$ 28,835	$ 57,437	$ 248,939
Add: (Gain)/loss on derivatives	$ (13,595)	$ (1,500)	$ 3,239	$ (1,119)	$ (12,975)
Less: Cash payments on derivatives settled	$ 2,601	$ (2,848)	$ (4,806)	$ (5,538)	$ (10,591)
Add: Depreciation, depletion, and amortization	$ 3,891	$ 3,824	$ 4,778	$ 5,231	$ 17,724
Less: Gain on sale of Superior	$ -	$ (17,812)	$ -	$ -	$ (17,812)
Less: Gain on disposition of assets	$ (3,753)	$ (5,676)	$ (4,149)	$ (36,372)	$ (49,950)
Add: Stock-based compensation expense	$ 1,408	$ 1,008	$ 1,479	$ 3,652	$ 7,547
Add: ARO accretion expense	$ 467	$ 478	$ 478	$ 457	$ 1,880
Add: Interest expense	$ 39	$ 41	$ 41	$ 43	$ 164
Add: Income tax expense	$ (74,646)	$ 27,180	$ 722	$ 1,234	$ (45,510)
Add: Reorganization expense	$ 81	$ 70	$ 12	$ 136	$ 299
Adjusted EBITDA	$ 51,143	$ 32,782	$ 30,629	$ 25,161	$ 139,715

Unit believes Adjusted EBITDA provides information useful in assessing operating and financial performance across periods. Unit computes Adjusted EBITDA as net income attributable to Unit Corporation before non-cash valuation changes for commodity derivatives; depreciation, depletion and amortization; interest expense; income tax expense; reorganization expense; asset impairments, if any; asset disposition gains and losses; non-cash share-based compensation; accretion on asset retirement obligations; and other items not related to normal operations. Adjusted EBITDA as defined by Unit may not be comparable to similarly titled measures used by other companies.

Appendix 2

Description	Amount
Standardized Measure [1]	$237 million
Discounted effect of future income tax expenses	$12 million
Pre-tax PV-10 value under SEC pricing [2]	$249 million
Impact of adjusting SEC pricing to forward strip pricing	($1) million
Pre-tax PV-10 value under forward strip pricing [3]	$248 million

[1]The standardized measure of discounted future net cash flows relating to proved oil, NGLs, and natural gas reserves (Standardized Measure) is calculated in accordance with US GAAP as the after-tax estimated future cash flows from proved reserves discounted at an annual rate of 10 percent. The benchmark price used for all future reserves was $78.22 per barrel of oil, $23.72 per barrel of NGLs, and $2.64 per Mcf of natural gas, then adjusted for price differentials, based on the 12-month historical average of the beginning-of-month prices in accordance with SEC rules.

[2] Pre-tax PV-10 value under SEC pricing is consistent with the Standardized Measure calculation, but excludes the effects of future income taxes. We view pre-tax PV-10 under SEC pricing as a useful measure of the value of our proved reserves relative to the values of proved reserves held by other companies as it excludes future income tax expenses which may vary based on the characteristics of the owner of the reserves rather than on the nature, location, and quality of the reserves themselves. We also believe that securities analysts and rating agencies use pre-tax PV-10 under SEC pricing in a similar manner.

[3] Pre-tax PV-10 value under forward strip pricing is consistent with the calculation of pre-tax PV-10 value under SEC pricing, but uses forward strip product pricing instead of average historical pricing as required by SEC rules. We view pre-tax PV-10 value under forward strip pricing as a useful measure of the value of our proved reserves both because it excludes future income tax expenses (as discussed above) and because forward strip pricing provides a more current, forward-looking indicator of value. The pricing used is $67.75/bbl oil and $3.36/mcf gas based on strip pricing as of 1/2/2024.