TENAZ ENERGY CORP. ANNOUNCES 2023 YEAR-END RESULTS

CALGARY, AB, March 28, 2024 /CNW/ - Tenaz Energy Corp. ("Tenaz", "We", "Our", "Us" or the "Company") (TSX: TNZ) is pleased to announce financial and operating results for the three months and year ended December 31, 2023.

The related audited consolidated financial statements, as well as Management's Discussion and Analysis ("MD&A") for the year ended December 31, 2023 and Annual Information Form ("AIF") as of December 31, 2023, are available on SEDAR+ at www.sedarplus.ca and on Tenaz's website at www.tenazenergy.com.

A webcast presentation to accompany this release is available on Tenaz's website at www.tenazenergy.com.

HIGHLIGHTS

Fourth Quarter and Year-End 2023 Results

- Production volumes averaged a record level of 3,135 boe/d[(1)] in Q4 2023. Canadian production of 2,028 boe/d reflected contributions from the new wells brought on-line from the 2023 campaign at Leduc-Woodbend ("LWB"). Production in the Dutch North Sea ("DNS") of 1,107 boe/d was consistent with the third quarter, despite unplanned facility downtime.
- Production volumes averaged 2,439 boe/d for full year 2023, more than double full year 2022 levels. Production was higher due to the acquisition of Netherlands assets and continued organic growth at LWB in Canada. Production from LWB was 30% higher year-over-year.
- All four wells in the 2023 program at LWB have been successfully put on production. Gross production rates during the fourth quarter averaged 225 boe/d (89% oil) per well.
- Funds flow from operations[(2)] ("FFO") for the fourth quarter was $13.4 million ($0.50/share[(3)]), 178% higher than Q3 2023 and 315% higher than Q4 2022. Higher quarter-over-quarter FFO resulted from higher production in Canada and higher prices for TTF[(4)] natural gas.
- FFO for full year 2023 was $28.9 million ($1.05/share), 236% higher than in 2022. Increased annual FFO primarily resulted from contributions from the new Netherlands assets and higher production in Canada, partially offset by higher transaction costs.
- Net income for full year 2023 was $26.5 million ($0.97/share), as compared to $5.2 million ($0.18/share) in 2022. Higher net income resulted primarily from the recognition of a gain on the acquisition of XTO Netherlands Ltd. ("XTO Acquisition") in Q3 2023, partially offset by increased G&A and transaction costs pertaining both to closed acquisitions and potential future transactions.
- We ended 2023 with positive adjusted working capital[(2)] of $49.3 million, an increase of $4.4 million over the prior quarter and $35.3 million over year-end 2022. The improvement was driven by free cash flow and the XTO Acquisition for the respective periods, partially offset by spending on decommissioning activity and share buybacks. We remain undrawn on our $10 million bank facility.
- During 2023, we deployed $3.9 million for our Normal Course Issuer Bid ("NCIB") program, repurchasing and retiring 1.3 million shares at an average price of $2.97/share. Since the beginning of the NCIB program in Q3 2022, we have retired 1.8 million common shares (6.1% of basic common shares) at an average cost of $2.63/share.

---

(1) The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Per boe amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel (1 bbl) of crude oil. Refer to "Barrels of Oil Equivalent" section included in the "Advisories" section.
(2) This is a non-GAAP and other financial measure. Refer to "Non-GAAP and Other Financial Measures" included in the "Advisories" section.
(3) Per share metrics calculated using the weighted average common shares for the applicable period.
(4) TTF represents posting price of Title Transfer Facility ("TTF") natural gas in the Netherlands.

- We have hedged approximately 40% of our expected European gas production for Q1 2024 through a physical swap at €55.75/MWh (approximately $24.12/Mcf). For Q2 and Q3 2024, we have hedged approximately 20% of our expected European gas production through a physical swap at €34.00/MWh (approximately $14.58/Mcf).
- During 2023, Tenaz delivered a total shareholder return of 83%, ranking TNZ in the top 1.3% of all TSX-listed issues.

Year-End 2023 Reserves(5)

- Proved Developed Producing ("PDP") reserves increased 22%, including a 17% increase in Canada through organic activities, reflecting a corporate reserve replacement ratio of 161%. PDP reserves at year-end totaled 3.7 million boe.
- Total Proved ("1P") reserves increased 6%, reflecting a reserve replacement ratio of 144%. 1P reserves at year-end totaled 9.3 million boe.
- Total Proved plus Probable ("2P") reserves increased 7%, reflecting a reserve replacement ratio of 195%. 2P reserves at year-end totaled 14.6 million boe.
- PDP Finding and Developing ("F&D")(6) costs (including future development capital ("FDC")) were $19.53/boe, resulting in a 2.2 organic recycle ratio based on our 2023 operating netback(2) of $43.18/boe. F&D costs (including FDC) were $23.44 and $22.10 at the 1P and 2P levels, generating organic recycle ratios of 1.8 and 2.0, respectively.
- PDP Finding, Developing and Acquisition Costs ("FD&A"), were $17.23/boe (including FDC), resulting in a 2.5 recycle ratio. FD&A costs (including FDC) were $19.69 and $17.15 at the 1P and 2P levels, generating recycle ratios of 2.2 and 2.5, respectively. For purposes of the calculation of FD&A costs and their corresponding recycle ratios, we have utilized a nil purchase price for the XTO acquisition. Actual net consideration for the XTO Acquisition was negative $42.8 million, due to acquiring positive working capital while not providing financial consideration to XTO. Had we utilized the negative purchase price for this acquisition, FD&A costs (including FDC) and their corresponding recycle ratios would have been negative values.
- Reserve life indices were 3.2 years, 8.1 years and 12.8 years, respectively, for PDP, 1P and 2P reserves, based on our Q4 2023 production rate.

Capital Activity and Outlook

- Capital expenditures(2) during full year 2023 were approximately $24.8 million. This total includes both Drilling and Development capital expenditures ("D&D CAPEX") and Exploration and Evaluation capital expenditures ("E&E CAPEX").
- Our 2023 Canadian development program included drilling, completing, equipping and tie-in of four gross (3.35 net) wells. Combining our Canadian investment program with Netherlands workover and facility investment, D&D CAPEX was $23.3 million. Full year D&D CAPEX for 2023 was within our guidance range of $20 to $24 million.
- During 2023, we elected to participate in FEED activities for the potential L10 Carbon Capture and Storage ("CCS") project in the Netherlands, which is included as E&E CAPEX due to the project's unsanctioned status. Full year 2023 E&E CAPEX totalled $1.5 million (100% of which related to L10 CCS).

---

(5) Reserves evaluated by McDaniel & Associates Consultants Ltd. in a report effective December 31, 2023 dated March 12, 2024. Refer to "Reserves".

(6) "FD&A Cost", "F&D Cost", "Reserves Replacement Ratio" and "Recycle Ratio" do not have standardized meanings and therefore may not be comparable with the calculation of similar measures for other entities. See "Information Regarding Disclosure on Oil and Gas Reserves and Operational Information" in this press release.

- In 2024, we plan D&D CAPEX of $23 to $25 million. The D&D CAPEX program includes a four (3.5 net) well drilling program in Canada and non-operated workovers, facility maintenance and studies at the F17a oil development project in the Netherlands. In addition, we forecast E&E CAPEX of $3 million for continued evaluation of the potential L10 CCS project.
- Production guidance for 2024 remains unchanged at 2,700 to 2,900 boe/d.

FINANCIAL AND OPERATIONAL SUMMARY

($000 CAD, except per share and per boe amounts)	Three months ended **Dec 31 2023**	Three months ended Sept 30 2023	Three months ended Dec 31 2022	Year Ended **Dec 31 2023**	Year Ended Dec 31 2022
FINANCIAL					
Petroleum and natural gas sales	**21,261**	15,051	**10,852**	**64,852**	34,087
Cash flow from operating activities	**8,927**	175	**4,809**	**15,176**	9,347
Funds flow from operations[1]	**13,401**	4,826	**3,236**	**28,862**	8,612
Per share – basic[1]	**0.50**	0.18	**0.11**	**1.05**	0.30
Per share – diluted[1]	**0.45**	0.16	**0.11**	**0.99**	0.30
Net income	**3,515**	20,907	**747**	**26,547**	5,237
Per share – basic	**0.13**	0.77	**0.03**	**0.97**	0.18
Per share – diluted[2]	**0.12**	0.71	**0.03**	**0.91**	0.18
Capital expenditures[1]	**2,967**	15,238	**4,988**	**24,855**	17,101
Adjusted working capital (net debt)[1]	**49,338**	44,937	**14,149**	**49,338**	14,149
Common shares outstanding (000)					
End of period – basic	**26,793**	27,145	**28,093**	**26,793**	28,093
Weighted average for the period – basic	**26,963**	27,292	**28,242**	**27,429**	28,424
Weighted average for the period – diluted	**29,970**	29,555	**28,244**	**29,053**	28,878
OPERATING					
Average daily production					
Heavy crude oil (bbls/d)	**1,342**	675	827	**917**	667
Natural gas liquids (bbls/d)	**75**	60	53	**64**	56
Natural gas (Mcf/d)	**10,310**	9,823	3,843	**8,749**	2,972
Total (boe/d)	**3,135**	2,372	1,520	**2,439**	1,218
Netbacks ($/boe)					
Petroleum and natural gas sales	**73.71**	68.97	77.59	**72.85**	76.67
Royalties	**(5.89)**	(4.60)	(11.12)	**(5.46)**	(13.38)
Transportation expenses	**(3.50)**	(3.68)	(2.60)	**(3.56)**	(2.29)
Operating expenses	**(19.36)**	(31.11)	(21.56)	**(25.23)**	(18.69)
Midstream income[1]	**4.86**	5.25	-	**4.90**	-
Operating netback[1]	**49.82**	34.83	42.31	**43.50**	42.31
BENCHMARK COMMODITY PRICES					
WTI crude oil (US$/bbl)[3]	**78.33**	82.18	82.63	**77.62**	94.23
WCS (CAD$/bbl)	**76.86**	93.12	77.39	**80.90**	98.53
AECO daily spot (CAD$/Mcf)[4]	**2.30**	2.61	5.23	**2.64**	5.43
TTF (CAD$/Mcf)	**18.52**	14.43	50.12	**17.72**	52.84

(1) This is a non-GAAP and other financial measure. Refer to "Non-GAAP and Other Financial Measures" in the section "Advisories".
(2) Per share metrics calculated using the weighted average common shares for the applicable period.
(3) WTI represents posting price of West Texas Intermediate ("WTI") crude oil.
(4) AECO Price means the Alberta Energy Company monthly index of Gas price.

PRESIDENT'S MESSAGE

We are pleased to provide our quarterly and annual report of our financial and operating results, along with our year-end independent reserve report. We had our strongest operating results since the inception of Tenaz, again reporting very strong reserve replacement and capital efficiencies. With respect to acquisitions, we continue to advance our pipeline of potential transactions, particularly in Europe and Latin America. We believe asset market conditions are in our favor with commodity prices at reasonable levels and little evidence that buyer competition has heated up.

Netherlands Operations

At mid-year, we made our second non-operated Netherlands acquisition when we added XTO Netherlands to our DNS portfolio. Our Netherlands production averaged 1,107 boe/d during Q4 2023, up 1% over Q3 2023. For full year 2023, Netherlands contributed 892 boe/d (99% TTF gas) at an average realized price of $16.65/Mcf.

European gas prices appear to have bottomed after this winter's weather-driven decrease. Despite another warm winter, European gas storage is slightly below last year's levels, and, as at March 27th, the prompt price remains at $11.92/Mcf, more than four times North American levels. The TTF forward price curve is largely flat, with an average price of $12.69/Mcf through 2027. We have hedged 40% of our Q1 2024 TTF exposure at $24.12/Mcf and 20% of Q2 and Q3 2024 at $14.58/Mcf.

Capital investment in the Netherlands upstream assets in 2023 totaled $4.4 million for well workover and facilities projects, managing to maintain flat production over the second half of 2023. We would expect to have roughly similar activity for 2024, yielding production levels slightly below those in the second half of 2023.

With the XTO Acquisition, we also increased our shareholding in the NGT midstream system by 10.1%, bringing our ownership in this high-reliability and valuable offshore gas gathering business to 21.4%. NGT is accounted for as an equity investment, whereby our interest in the net income of NGT is included in our results as income from associate. Tenaz estimates that full year 2023 NGT net income was approximately $27 million ($6 million to Tenaz's equity interest). Dividend payments from NGT have traditionally occurred in the first half of the subsequent year. Payout of earnings in the form of dividends from NGT can vary from year to year, but typically closely matches the underlying earnings from the prior financial year. Tenaz received an interim dividend of €2.2 million ($3.1 million) at the end of Q4 2023.

In addition to its desirable attributes as a natural gas gathering and processing business, NGT also represents critical infrastructure that may also have a key long-term role in the energy transition in Europe. The NGT system is a hard-to-replicate pipeline network that is certified to transport hydrogen and may provide a cost-effective and environmentally-benign way to connect future offshore hydrogen production with onshore users.

Tenaz also has an 11.35% participation right in the L10 CCS project, which is intended to provide a permanent storage solution for CO_2 sourced from industrial emitters. This project has entered the Front-End Engineering Design ("FEED") phase, which is scheduled to continue until the end of Q2 2025. The FEED phase is required for comprehensive project planning before making the Final Investment Decision ("FID"), with FID currently slated for Q2/Q3 2025. In the event of a positive FID, project start up is estimated to occur in 2028, with injection of up to five million tonnes per annum of CO_2. The L10 gas field, located approximately 50 km offshore in the DNS, has a potential storage capacity of 96 MT. The combined storage capacity of the L10 and other pools potentially amenable to CCS in the Tenaz license areas is approximately 150 MT.

Canadian Operations

Production from the Leduc-Woodbend ("LWB") field averaged 2,028 boe/d in Q4 2023, an increase of 59% compared to Q3 2023, driven by strong contributions from our four well (3.35 net) drilling program which was fully on production in the fourth quarter. For 2023 as a whole, production averaged 1,547 boe/d as compared to 1,193 boe/d in 2022, an increase of 30%.

The four wells drilled in 2023 are the longest to-date in the LWB field, with total measured depths ranging from 5,000 to 5,700 meters. These wells also have the longest completed horizontal sections at LWB, with completion intervals ranging from 3,600 to 4,200 meters. Despite longer laterals and an increased number of fracs, these wells were drilled entirely within the targeted Rex member of the Mannville group and were completed with 97% of frac stages successfully placed. The new wells have generated impressive rates, with a Q4 2023 average rate of 225 boe/d per well and a very high oil percentage of 89% in their product mix. This strong average well rate was achieved even though one of the wells only has 40% of its lateral open to production due to a fish stuck in the lateral. We view the improving technical indicators and production levels on the Rex wells as evidence of the effectiveness of Tenaz's engineering and geoscience approach, which we will also seek to apply on future international acquisitions that we operate.

Capital expenditures for Canada in 2023 totaled approximately $19 million, more than 80% of which was for the four-well DCET (drill, complete, equip and tie-in) program, with the remainder primarily for facility modifications and land acquisition. As a result of the success of the drilling program and ongoing efforts to reduce well failures and other sources of downtime, unit operating expense in Canada decreased to $12.47/boe in Q4 2023, a 31% reduction from Q3 2023. For 2023 as a whole, unit operating expense decreased to $16.55/boe, 6% lower than in 2022.

Looking forward to 2024, we expect to again conduct a four well (3.5 net) drilling program in LWB at roughly comparable CAPEX levels to last year. We believe that this program will continue to generate strong Canadian production growth, with average production in 2024 expected to increase on the order of 20% from 2023 levels.

With respect to commodities hedging, we have hedged approximately 25% of our winter 2024/25 gas production at an AECO marker price of $3.28/Mcf. Our crude oil produced at LWB sells for approximately the WCS marker price and does not require diluent. We are currently unhedged for both WCS differentials and the underlying WTI index. Though we may hedge as opportunities arise, we have a constructive view of both world oil fundamentals and the Canadian transport situation as start-up of the Trans Mountain pipeline approaches. Moreover, our unlevered financial position allows us the flexibility to maintain a greater degree of operating leverage through unhedged commodity exposure.

Reserves

We commissioned McDaniel and Associates Consultants Ltd. ("McDaniel") to provide an independent year-end 2023 reserves evaluation report (the “McDaniel Report”), dated March 12, 2024 with an effective date of December 31, 2023. Total Proved plus Probable (“2P”) reserves increased 7%, reflecting a reserve replacement ratio of 195%. The increase in reserves was driven by the XTO Acquisition and our development activities at LWB, partially offset by production during 2023. At year-end 2023, 2P reserves totaled 14.6 million boe, with a reserve life index of 12.8 years calculated using our record level of production in Q4 2023.

Organic F&D costs (including FDC) were $22.10/boe at the 2P level, generating a recycle ratio of 2.0. When calculating FD&A costs, we have elected a conservative presentation by setting consideration for the XTO Acquisition at a zero cost. With this assumption, FD&A costs (including FDC) were $17.14/boe, generating a recycle ratio of 2.5. Had we utilized the actual negative purchase price for XTO, FD&A costs (including FDC) and recycle ratio would have had negative values.

The McDaniel Report is discussed in more detail later in this press release.

Corporate Discussion

Our corporate guidance levels for 2024 remain unchanged at 2,700 to 2,900 boe/d of production and $23 to $25 million of D&D CAPEX.

With respect to corporate liquidity, positive adjusted working capital was $49.3 million at the end of 2023, an increase of $4.4 million over the prior quarter and $35.3 million over year-end 2022. The improvement was driven by free cash flow and the XTO Acquisition for the respective periods, partially offset by spending on decommissioning activity and share buybacks. We remain undrawn on our $10 million bank facility.

During 2023, we expended $3.9 million under our Normal Course Issuer Bid (“NCIB”) program, buying back 1.3 million shares at an average price of $2.97/share. Since inception, the NCIB program has retired 1.9 million shares at an average price of $2.70/share.

It has now been more than two years since we executed our recapitalization of Altura Energy in Q4 2021. During that time, we have increased our production rate more than three-fold, doubling Canadian production through organic activity and introducing overseas production through our first two Netherlands transactions. Funds flow from operations (“FFO”) for 2023 was $28.9 million, an approximately eight-fold increase from before the recapitalization, driven both by higher production and higher margins. Regarding our balance sheet, we have moved from a net debt position of $3.5 million prior to the recapitalization to $49.3 million in positive adjusted working capital at year-end 2023, and have an undrawn bank facility.

In terms of market performance, Tenaz shares now trade at twice the level then at the time of the recapitalization of Altura. During 2023, Tenaz delivered a total shareholder return of 83%, ranking TNZ in the top 1.3% of all TSX issuers, and among the very best returns for companies in the oil and gas industry.

More importantly than these statistical improvements, we believe that we have demonstrated, at least to a modest degree, both elements of our overseas acquisition-oriented business model. First, we believe there is a great value opportunity in overseas acquisitions. In the Netherlands, we have executed two small but highly-accretive transactions in a high-value commodity market. We hope that these transactions will prove to be forerunners of larger future acquisitions from our transaction pipeline. Second, we believe that we will be able to significantly improve production profiles and cost levels when we operate assets acquired in the overseas market. We have demonstrated such capability at the LWB field, where our geologic description, drilling methods and frac designs have significantly improved production results and capital efficiencies. We find it encouraging that such technical improvement could be achieved when taking over from a quality operator like Altura, which discovered this substantial and previously-overlooked oil development project. Our assessment is that the North American oil and gas industry is in general much more efficient than the overseas industry, especially with respect to the more mature producing assets that we are targeting. The combination of these two factors - better value at acquisition and more opportunities for operational improvement - is what we believe creates such outsized opportunities for high returns in the overseas market.

We appreciate the hard and effective work of our team members in pursuing this strategy. In many ways, it is not an easy business model, requiring detailed technical, commercial and financial work to evaluate and structure transactions. Because of their complexity and the inherent slowness of the overseas asset market, these acquisitions typically take a long time to bring to fruition with many twists and turns along the way. These challenges, in fact, increase the opportunity to achieve high returns on capital. Our team of technical and finance professionals recognizes this and seeks to take advantage of the complexities to strike more favorable terms and structures for Tenaz.

Our team is invested in Tenaz and fully aligned with our broader shareholder group in pursuit of our shared success. As we have previously stated, we can make no guarantees regarding the certainty or timing of the next transaction, but we are optimistic about bringing quality assets into our portfolio. When we do so, we are confident that our investments will be consistent with our stated financial and strategic goals. We appreciate the continued support of our shareholders as we pursue our vision for Tenaz.

/s/ Anthony Marino

President and Chief Executive Officer
March 28, 2024

RESERVES

The McDaniel Report was prepared in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Additional reserves information as required under NI 51-101 is included in Tenaz's Annual Information Form for the year ended December 31, 2023 available on SEDAR+ at www.sedarplus.ca and on Tenaz's website at www.tenazenergy.com.

The following tables are a summary of Tenaz's crude oil, natural gas liquids ("NGLs") and natural gas reserves, as evaluated by McDaniel in the McDaniel Report. Under NI 51-101 Tenaz is required to report its reserves and net present value estimates using forecast pricing and costs. The forecast prices reflected in the net present values are based on an average of the price decks of three independent engineering firms, GLJ Ltd., Sproule Associates Limited and McDaniel & Associates Consultants Ltd. (the "Consultant Average Price Forecast") at January 1, 2024 (see the Company's AIF). It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no assurance the estimated reserves will be recovered. It is important to note that the recovery and reserves estimates provided herein are estimates only. Actual reserves may be greater or less than the estimates. Reserves information may not add up due to rounding. Consistent with 2022 year-end reserves, and in accordance with guidance in the COGE Handbook, the McDaniel Report includes all abandonment, decommissioning and reclamation obligations ("ADR"), including all ADR associated with both active and inactive wells regardless of whether such wells had any attributed reserves.

Summary of Gross Reserves as at December 31, 2023

	Company Gross Reserves(1)(2)				
Reserve Category	**Light Crude Oil & Medium Crude Oil (Mbbl)**	**Heavy Crude Oil (Mbbl)**	**Conventional Natural Gas (MMcf)**	**Natural Gas Liquids (Mbbl)**	**Oil Equivalent (Mboe)**
Proved					
Proved Developed Producing	105	1,121	14,036	121	3,687
Proved Developed Non-Producing	-	37	725	6	163
Proved Undeveloped	-	2,899	13,809	204	5,404
Total Proved	**105**	**4,056**	**28,570**	**331**	**9,254**
Total Probable	**21**	**2,570**	**15,530**	**188**	**5,367**
Total Proved plus Probable(3)	**126**	**6,626**	**44,100**	**519**	**14,621**

(1) Gross reserves are Company working interest reserves before royalty deductions.
(2) Based on the January 1, 2024 Consultant Average Price Forecast.
(3) Numbers may not add due to rounding.

Reconciliation of Reserves for 2023

	Company Gross Reserves(1)(2)				
	Light Crude Oil & Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Total Proved					
December 31, 2022	101	3,881	26,392	375	8,756
Extensions and improved recovery(3)	-	224	1,297	19	460
Technical Revisions(4)	45	270	1,138	15	520
Acquisitions	-	-	3,154	3	529
Economic Factors	(15)	(10)	(386)	(59)	(148)
Production	(26)	(309)	(3,025)	(23)	(862)
December 31, 2023(5)	**105**	**4,056**	**28,570**	**331**	**9,254**
Total Proved plus Probable					
December 31, 2022	117	6,174	40,512	586	13,629
Extensions and improved recovery(3)	-	517	2,474	37	966
Technical Revisions(4)	55	257	275	3	361
Acquisitions	-	-	4,370	4	733
Economic Factors	(20)	(14)	(507)	(88)	(205)
Production	(26)	(309)	(3,025)	(23)	(862)
December 31, 2023(5)	**126**	**6,626**	**44,100**	**519**	**14,621**

(1) Gross reserves are Company working interest reserves before royalty deductions.
(2) Based on the January 1, 2024 Consultant Average Price Forecast.
(3) Extensions and Improved Recovery includes all new wells booked during the year at Leduc-Woodbend.
(4) Technical revisions were realized in all reserve categories. The revisions were driven by performance deviations from earlier estimates.
(5) Numbers may not add due to rounding.

Summary of Net Present Values of Future Net Revenue as at December 31, 2023

Benchmark crude oil and NGL prices used are adjusted for quality of crude oil or NGL produced, and for transportation costs. The calculated after-tax net present values ("NPVs") are based on the Consultant Average Price Forecast at January 1, 2024. The NPVs include ADR but do not include a provision for interest, debt service charges and general and administrative expenses. It should not be assumed that the NPV estimate represents the fair market value of the reserves.

	After Tax Net Present Value Discounted at(1)(2)				
Reserve Category	**0% ($000)**	**5% ($000)**	**10% ($000)**	**15% ($000)**	**20% ($000)**
Proved					
Proved Developed Producing	(28,752)	17,793	39,732	49,792	53,940
Proved Developed Non-Producing	3,953	3,319	2,825	2,430	2,109
Proved Undeveloped	71,696	49,390	34,453	24,470	17,465
Total Proved	**46,898**	**70,501**	**77,099**	**76,693**	**73,514**
Total Probable	**124,368**	**87,697**	**65,066**	**50,314**	**40,202**
Total Proved plus Probable(3)	**171,266**	**158,198**	**142,165**	**127,006**	**113,716**

(1) Based on the January 1, 2024 Consultant Average Price Forecast.
(2) Includes abandonment and reclamation costs as defined in NI 51-101.
(3) Numbers may not add due to rounding.

Finding and Development Costs and Recycle Ratios

FDC reflects the future capital costs, as provided by the Company and included in the McDaniel Report, to bring Tenaz's proved and probable developed and undeveloped reserves on production. Changes in forecasted FDC occur annually as a result of development activities, acquisition and disposition activities, changes in capital cost estimates based on improvements in well design and performance, and changes in service costs.

Tenaz has incurred the following F&D(5) and FD&A(5) costs including FDC. For purposes of the calculation of FD&A costs and their corresponding recycle ratios, we have utilized a nil purchase price for the XTO acquisition. Actual net consideration for the XTO Acquisition was negative $42.8 million, due to acquiring positive working capital while not providing financial consideration to XTO. Had we utilized the negative purchase price for this acquisition, FD&A costs (including FDC) and their corresponding recycle ratios would have had negative values.

	2023		
	PDP	**1P**	**2P**
F&D and FD&A Costs per boe(1)(2)(3)(5)			
F&D Costs per boe (including FDC)	$19.53	$23.44	$22.10
FD&A Costs per boe (including FDC)	$17.23	$19.69	$17.15
Recycle Ratio (x) (2)(4)(5)			
F&D (including FDC)	2.2	1.9	2.0
FD&A (including FDC)	2.5	2.2	2.5

(1) Barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. See "Information Regarding Disclosure on Oil and Gas Reserves and Operational Information" in this press release.
(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital generally will not reflect total finding and development costs related to reserve additions for that year.
(3) The calculation of F&D and FD&A costs includes the change in FDC required to bring proved and probable undeveloped and developed reserves into production. The F&D or FD&A number is calculated by dividing the identified capital expenditures by applicable reserve additions including extensions, infills, revisions, acquisitions and disposals, and economic factors, after changes in FDC costs.
(4) Recycle Ratio is calculated by dividing operating netback (a non-GAAP measure) by the cost of adding reserves ("F&D Cost").
(5) "FD&A Cost", "F&D Cost", and "Recycle Ratio" do not have standardized meanings and therefore may not be comparable with the calculation of similar measures for other entities. See "Information Regarding Disclosure on Oil and Gas Reserves and Operational Information" in this press release.

CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES

An independent resources report on the resource potential of the Company's DNS assets (the "Resources Report") was prepared by McDaniel, the Company's independent qualified reserves evaluator, in accordance with the standards contained in the COGE Handbook and the definitions contained in NI 51-101 and the COGE Handbook. The Resources Report has an effective date of December 31, 2023 and a preparation date of March 12, 2024.

Contingent and prospective resources evaluated in the Resources Report are located offshore in the Dutch North Sea in the country of the Netherlands. Contingent resources reflect the undeveloped Rembrandt and Vermeer oil discoveries operated by Wintershall Noordzee B.V. ("**Wintershall**") and two undeveloped natural gas discoveries on the Neptune Energy Netherlands B.V. ("**Neptune**") operated licenses. Prospective resources reflect 15 exploration prospects on licenses that are operated by Wintershall and Neptune. Prospective volumes do not reflect any scaling factor for chance of development. As a non-operator interest holder the Company is unable to guarantee that any resource projects will be pursued.

The Resources Report summarizes estimates of crude oil and natural gas contingent resources and prospective resources of the Company and the net present values of best estimate contingent (2C) resources using forecast prices and costs.

An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the Company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development and chance of discovery to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Information relating to resources contains forward-looking statements. See "*Note Regarding Forward-Looking Statements*".

The tables below summarize the volumes and economic values in the Resources Report

Netherlands Prospective Resources

Summary of Prospective Resources Estimates – Company Gross Values
(Forecast Prices and Costs)

			Company Gross Values(1)(2) Prospective Resources - Unrisked(3)(7)				
Prospect	**Type**	**Working Interest**	**Low (P90)(10) (Mboe)**	**P50(10) (Mboe)**	**Mean(10) (Mboe)**	**High (P10)(10) (Mboe)**	**Risked Resources Mean(4) (Mboe)**
F17a Block(9)	Crude Oil	5.00%	373	675	752	1,232	379
L10 Block	Natural Gas	21.43%	2,809	5,428	6,168	10,461	4,158
L11a Block	Natural Gas	21.43%	1,309	2,334	2,563	4,120	1,845
N7b Block	Natural Gas	17.86%	1,849	3,335	3,680	5,903	1,456
Total(5)(6)(7)(8)			**6,340**	**11,772**	**13,162**	**21,717**	**7,837**

(1) Gross values are Company working interest resources.
(2) Based on the January 1, 2024 Consultant Average Price Forecast.
(3) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be economically viable or technically feasible to produce any portion of the resources.

(4) These are partially risked prospective resources that take into account the chance of discovery but not the chance of development, which is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. The chance of development was estimated to be 60% for crude oil and 75% for natural gas.
Chance of Discovery for the prospects in each block is as follows:
F17a Block (Crude Oil) CK2 (50%)
L10 Block (Natural Gas) Limonite (72%), Topaz (64%), Malachite (63%), Sapphire (64%), L10-21 (72%)
L11a Block (Natural Gas) Fresnel (72%), Obsidian (72%), L11-2 (72%)
N7b Block (Natural Gas) Snapper (65%), Sole (57%), Crab East (49%), Crab West (49%), Crab East Upper Sloch (29%), Crab West Upper Sloch (29%)
(5) Total based on the arithmetic aggregation of the prospects. Numbers may not add due to rounding.
(6) The unrisked total is not representative of the portfolio unrisked total and is provided to give an indication of the resources range assuming all the prospects are successful.
(7) Volumes listed are full life volumes, prior to any cutoffs due to economics.
(8) Based on a Mcf to boe conversion of 6 to 1. A boe conversion of 6 to 1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(9) Crude oil prospects with expected quality consistent with prior discoveries.
(10) Refer to "Information Regarding Disclosure of Crude Oil and Natural Gas Resources" in the section "Advisories".

Netherlands Contingent Resources

Summary of Contingent Resources Estimates – Company Gross Values
(Forecast Prices and Costs)

Crude Oil Property	Working Interest	Company Gross Values(1)(2) Contingent Resources - Unrisked(3)(4)(6) 1C(10) (Mbbl)	2C(10) (Mbbl)	3C(10) (Mbbl)	Chance of Discovery(5)	Risked Resources Mean pre-COD(5) (Mbbl)
Vermeer(7)	5.00%	323	982	1,902	100%	1,060
Rembrandt(7)	5.00%	1,026	1,482	1,986	100%	1,496
L11-07	21.43%	-	-	-	100%	-
L10-19	21.43%	-	-	-	100%	-
Total Crude Oil(8)		**1,349**	**2,464**	**3,888**		**2,557**

Natural Gas Property	Working Interest	Company Gross Values(1)(2) Contingent Resources - Unrisked(3)(4)(6) 1C(10) (MMcf)	2C(10) (MMcf)	3C(10) (MMcf)	Chance of Discovery(5)	Risked Resources Mean pre-COD(5) (MMcf)
Vermeer	5.00%	-	-	-	100%	-
Rembrandt	5.00%	-	-	-	100%	-
L11-07	21.43%	3,433	4,905	6,635	100%	4,982
L10-19	21.43%	3,070	6,239	11,635	100%	6,907
Total Natural Gas(8)		**6,502**	**11,144**	**18,270**		**11,889**

Total Oil Equivalent(9)	Working Interest	Company Gross Values(1)(2) Contingent Resources - Unrisked(3)(4)(6) 1C(10) (Mboe)	2C(10) (Mboe)	3C(10) (Mboe)	Chance of Discovery(5)	Risked Resources Mean pre-COD(5) (Mboe)
Vermeer	5.00%	323	982	1,902	100%	1,060
Rembrandt	5.00%	1,026	1,482	1,986	100%	1,496
L11-07	21.43%	572	817	1,106	100%	830
L10-19	21.43%	512	1,040	1,939	100%	1,151
Total Oil Equivalent(8)		**2,432**	**4,322**	**6,933**		**4,538**

(1) Gross values are Company working interest resources.
(2) Based on the January 1, 2024 Consultant Average Price Forecast.

(3) There is no certainty that it will be commercially viable to produce any portion of the resources.
(4) Company gross contingent resources are based on the working interest share of the property gross resources.
(5) These are unrisked values that do not take into account the chance of development, which is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. The chance of development was estimated to be 60% for crude oil and 75% for natural gas.
(6) These are economic contingent resources and are sub-classified in terms of maturity as development on hold.
(7) Vermeer crude oil is 30º API and Rembrandt crude oil is 23º API.
(8) Numbers may not add due to rounding.
(9) Based on a Mcf to boe conversion of 6 to 1. A BOE conversion of 6 to 1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(10) Denotes Contingent - Low estimate (“1C”), Contingent - Best estimate (“2C”) and Contingent – High estimate (“3C”). Refer to “Information Regarding Disclosure of Crude Oil and Natural Gas Resources” included in the section “Advisories”.

Netherlands Summary of Company Share of Net Present Values as at December 31, 2023

	Unrisked Net Present Value Discounted at[1]				
Best Estimate Contingent (2C) Resources Total[3][4]	**0% ($000)**	**5% ($000)**	**8% ($000)**	**10% ($000)**	**15% ($000)**
Before Tax Net Present Values					
L11-07 & L10-19 natural gas	82,467	55,995	44,230	37,682	24,800
Vermeer & Rembrandt crude oil[5]	189,108	101,132	70,589	55,642	30,250
Best Estimate Contingent Resources Total[2]	**271,574**	**157,127**	**114,818**	**93,324**	**55,050**
After Tax Net Present Values					
Best Estimate Contingent Resources Total	**198,534**	**111,110**	**78,823**	**62,410**	**33,163**

(1) Based on the January 1, 2024 Consultant Average Price Forecast.
(2) Numbers may not add due to rounding.
(3) There is no certainty that it will be commercially viable to produce any portion of the resources.
(4) These are unrisked values that do not take into account the chance of development, which is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. The chance of development was estimated to be 60% for crude oil and 75% for natural gas.
(5) Vermeer crude oil is 30º API and Rembrandt crude oil is 23º API.

About Tenaz Energy Corp.

Tenaz is an energy company focused on the acquisition and sustainable development of international oil and natural gas assets capable of returning free cash flow to shareholders. In addition, Tenaz conducts development of a semi-conventional oil project in the Rex member of the Upper Mannville group at Leduc-Woodbend in central Alberta and has non-operated natural gas production assets offshore Netherlands.

ADVISORIES

Non-GAAP and Other Financial Measures

This press release contains references to measures used in the oil and natural gas industry such as "funds flow from operations", "funds flow from operations per share", "funds flow from operations per boe", "adjusted working capital (net debt)", and "operating netback". The data presented in this press release is intended to provide additional information and should not be considered in isolation or as a substitute for measures of performance prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board and sometimes referred to in this press release as Generally Accepted Accounting Principles ("GAAP"). These reported non-GAAP measures and their underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of other companies where similar terminology is used. Where these measures are used, they should be given careful consideration by the reader.

Funds flow from operations

Tenaz considers funds flow from operations to be a key measure of performance as it demonstrates the Company's ability to generate the necessary funds for sustaining capital, future growth through capital investment, and settling liabilities. Funds flow from operations is calculated as cash flow from operating activities plus midstream income and before changes in non-cash operating working capital and decommissioning liabilities settled. Funds flow from operations is not intended to represent cash flows from operating activities calculated in accordance with IFRS. A summary of the reconciliation of cash flow from operating activities to funds flow from operations, is set forth below:

($000)	Q4 2023	Q3 2023	Q4 2022	2023	2022
Cash flow from operating activities	**8,927**	175	4,809	**15,176**	9,347
Change in non-cash operating working capital	**(3,113)**	1,186	(1,826)	**274**	(991)
Decommissioning liabilities settled	**6,187**	2,319	256	**9,048**	256
Midstream income	**1,400**	1,146	-	**4,364**	-
Funds flow from operations	**13,401**	4,826	3,236	**28,862**	8,612

Funds flow from operations per share is calculated using basic and diluted weighted average number of shares outstanding in the period.

Funds flow from operations per boe is calculated as funds flow from operations divided by total production sold in the period.

Capital Expenditures

Tenaz considers capital expenditures to be a useful measure of the Company's investment in its existing asset base calculated as the sum of drilling and development costs and exploration and evaluation costs. Exploration and evaluation asset additions (being exploration and evaluation costs) and property, plant and equipment additions (being drilling and development costs) are taken from the consolidated statements of cash flows that is most directly comparable to cash flows used in investing activities. The reconciliation to financial statement measures is set forth below.

($000)	Q4 2023	Q3 2023	Q4 2022	2023	2022
Exploration and evaluation expenditures	**357**	246	-	**1,519**	-
Property, plant and equipment expenditures	**2,610**	14,992	4,988	**23,336**	17,101
Capital expenditures	**2,967**	15,238	4,988	**24,855**	17,101

Free Cash Flow ("FCF")

Tenaz considers free cash flow to be a key measure of performance as it demonstrates the Company's excess funds generated after capital expenditures for potential shareholder returns, acquisitions, or growth in available liquidity. FCF is a non-GAAP financial measure and is comprised of funds flow from operations less capital expenditures. A summary of the reconciliation of the measure, is set forth below:

($000)	Q4 2023	Q3 2023	Q4 2022	2023	2022
Funds flow from operations	**13,401**	4,826	3,236	**28,862**	8,612
Less: Capital expenditures	**(2,967)**	(15,238)	(4,988)	**(24,855)**	(17,101)
Free cash flow	**10,454**	(10,412)	(1,752)	**4,007**	(8,489)

Midstream Income

Tenaz considers midstream income an integral part of determining operating netback. Operating netback assists management and investors with evaluating operating performance. Tenaz's midstream income consists of the equity-accounted income from its associate, Noordgastransport B.V.("NGT") prior to the amortization of the fair value increment recognized on NGT at the time of the acquisition. Under IFRS, investments in associates are accounted for using the equity method of accounting. Income from associate is Tenaz's share of the investee's net income. Operating netback is disclosed in the "Operating Netback" section.

($000)	***Q4 2023***	*Q3 2023*	*Q4 2022*	***2023***	*2022*
Income from associate	***543***	*1,146*	*-*	***3,507***	*-*
Plus: Amortization of fair value increment of NGT	***857***	*-*	*-*	***857***	*-*
Midstream income	***1,400***	*1,146*	*-*	***4,364***	*-*

Adjusted working capital (net debt)

Management views adjusted working capital (net debt) as a key industry benchmark and measure to assess the Company's financial position and liquidity. Adjusted working capital (net debt) is calculated as current assets less current liabilities, excluding the fair value of financial instruments. Tenaz's adjusted working capital (net debt) as at December 31, 2022 and 2021 is summarized as follows:

($000)	***December 31, 2023***	***December 31, 2022***
Current assets	***92,488***	*72,317*
Current liabilities	***(43,988)***	*(58,749)*
Net current assets	***48,500***	*13,568*
Exclude fair value of financial instruments	***838***	*476*
Adjusted working capital (net debt)(1)	***49,338***	*14,044*

Operating Netback

Tenaz calculates operating netback on a dollar and per boe basis, as petroleum and natural gas sales less royalties, operating costs and transportation costs, plus midstream income (as described above). Operating netback is a key industry benchmark and a measure of performance for Tenaz that provides investors with information that is commonly used by other crude oil and natural gas producers. The measurement on a per boe basis assists management and investors with evaluating operating performance on a comparable basis with other issuers. Tenaz's operating netback is disclosed in the "Financial and Operational Summary" section of this press release.

Information Regarding Disclosure of Oil and Gas Reserves and Operational Information

All amounts in this press release are stated in Canadian dollars unless otherwise specified. Tenaz's crude oil, natural gas liquids, and natural gas reserves statement for the year ended December 31, 2023, is contained within the Company's AIF. The AIF is available on SEDAR+ at www.sedarplus.ca and on the Company's website at www.tenazenergy.com.The recovery and reserve estimates are estimates only and there is no guarantee that the estimated reserves will be recovered.

This press release contains metrics commonly used in the oil and natural gas industry, such as "reserve life indices", "recycle ratio", "finding and development (F&D) costs", "finding, development and acquisition (FD&A) costs", and "operating netback". Each of these metrics is determined by Tenaz as specifically set forth in this press release. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included to provide readers with additional information to evaluate the Company's performance however, such metrics should not be unduly relied upon for investment or other purposes. Management uses these metrics for its own performance measurements and to provide readers with measures to compare Tenaz's performance over time.

Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D costs related to reserves additions for that year.

Management uses these oil and natural gas metrics for its own performance measurements and to provide shareholders with measures to compare Tenaz's performance over time, however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

Information Regarding Disclosure of Crude Oil and Natural Gas Resources

The resources estimates in this press release are derived from the Resources Report. The following provides the definitions of the various resource categories used in this press release as set out in the COGE Handbook. "Contingent resource" and "prospective resource" are not, and should not be confused with, petroleum and natural gas reserves.

Contingent resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.

The primary contingencies which currently prevent the classification of the contingent resource as reserves include but are not limited to: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; crude oil and natural gas prices internationally in jurisdictions in which Tenaz operates; demonstration of economic viability; future drilling program and testing results; further reservoir delineation and studies; facility design work; corporate commitment; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

Prospective resources are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have two risk components, the chance of discovery and the chance of development. There is no certainty that the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Application of any geological and economic chance factor does not equate prospective resources to contingent resources or reserves.

Low estimate prospective resource is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best estimate prospective resource is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High estimate prospective resource is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Mean estimate prospective resource is the arithmetic average from the probabilistic assessment.

Although the Company has identified prospective resources, there are numerous uncertainties inherent in estimating oil and gas resources, including many factors beyond the Company's control and no assurance can be given that the indicated level of resources or recovery of hydrocarbons will be realized. In general, estimates of recoverable resources are based upon a number of factors and assumptions made as of the date on which the resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties and the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. There are several significant negative factors relating to the prospective resource estimate which include (i) structural events that are well defined seismically and are low risk, however, reservoir quality, seal, hydrocarbon migration and associated hydrocarbon column estimates are more at risk than the former, (ii) well costs are very high due to the exploratory nature of the initial group of wells, (iii) due to limited infrastructure proximate to the prospects, gas discoveries may be stranded for some time until infrastructure is in place, which may take some time due to the remoteness of the prospects and costs associated with same, and (iv) other factors which are not within the control of the Company.

There is no certainty that any portion of the prospective resources will be discovered. There is no certainty that it will be commercially viable to produce any portion of the contingent resources or prospective resources or that Tenaz will produce any portion of the volumes currently classified as contingent resources or prospective resources. All contingent resources and prospective resources evaluated by McDaniel were deemed economic at the effective date of December 31, 2023. The estimates of contingent resources and prospective resources involve implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated and that the resources can be profitably produced in the future.

The risked net present value of the future net revenue from the contingent resources and prospective resources does not represent the fair market value. Actual contingent resources and prospective resources (and any volumes that may be reclassified as reserves) and future production therefrom may be greater than or less than the estimates provided herein.

The resource estimates are estimates only and there is no guarantee that the estimated resources will be recovered.

Barrels of Oil Equivalent

The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Per boe amounts have been calculated by using the conversion ratio of six thousand cubic feet (6 Mcf) of natural gas to one barrel (1 bbl) of crude oil. The boe conversion ratio of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Forward-looking Information and Statements

This press release contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "budget", "forecast", "guidance", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "could", "believe", "plans", "potential", "intends", "strategy" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this press release contains forward-looking information and statements pertaining to: Tenaz's capital plans and budget; our anticipated operational and financial performance; forecasted average production volumes; our NCIB; the ability to grow our assets domestically and internationally; statements relating to a potential CCS project; estimates of reserves and resources, and net present values; and the corporate strategy proposed by the Tenaz management team.

The forward-looking information and statements contained in this press release reflect several material factors and expectations and assumptions of the Company including, without limitation: the continued performance of the Company's oil and gas properties in a manner consistent with its past experiences; that the Company will continue to conduct its operations in a manner consistent with past operations; expectations regarding future development; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes; expectations regarding future acquisition opportunities; the accuracy of the estimates of the Company's reserves volumes, or contingent resources or prospective resources; certain commodity price, interest rate, inflation and other cost assumptions; the continued availability of oilfield services; and the continued availability of adequate debt and equity financing and cash flow from operations to fund its planned expenditures. The Company believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations, and assumptions will prove to be correct.

The forward-looking information and statements included in this press release are not guarantees of future performance and should not be unduly relied *upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of the Company's products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of the Company or by third party operators of the Company's properties, increased debt levels or debt service requirements; inaccurate estimation of the Company's oil and gas reserve volumes, or contingent resources or prospective resources; limited, unfavorable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; and certain other risks detailed from time to time in the Company's public documents.*

The forward-looking information and statements contained in this press release speak only as of the date of this press release, and the Company does not assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

For further information, contact:

Tenaz Energy Corp.

investors@tenazenergy.com

Anthony Marino
President and Chief Executive Officer
Direct: 587 330 1983

Bradley Bennett
Chief Financial Officer
Direct: 587 330 1714