TALOS ENERGY

2022
ANNUAL REPORT

We Provide Energy Prosperity to Improve Lives

DRIVING SUCCESS THROUGH STRATEGIC VISION

Talos Energy is an innovative, industry-leading energy company focused on Upstream Exploration & Production and Carbon Capture & Sequestration ("CCS").

UPSTREAM

Talos is one of the largest independent offshore exploration and production operators in the United States, with a diverse footprint spanning the Gulf of Mexico.

Talos maintains a strong technical skill set focused on conventional geology, geophysics, and reservoir engineering and decades of operational experience spanning from the U.S. Gulf Coast to ultra-deepwater in the Gulf of Mexico. These capabilities allow Talos to unlock new resources, providing a secure, reliable, and responsible energy supply to the global marketplace.

CCS

Talos is also leveraging its core skill sets and decades of experience with conventional geology and Gulf Coast operations to pursue the development of major CCS projects.

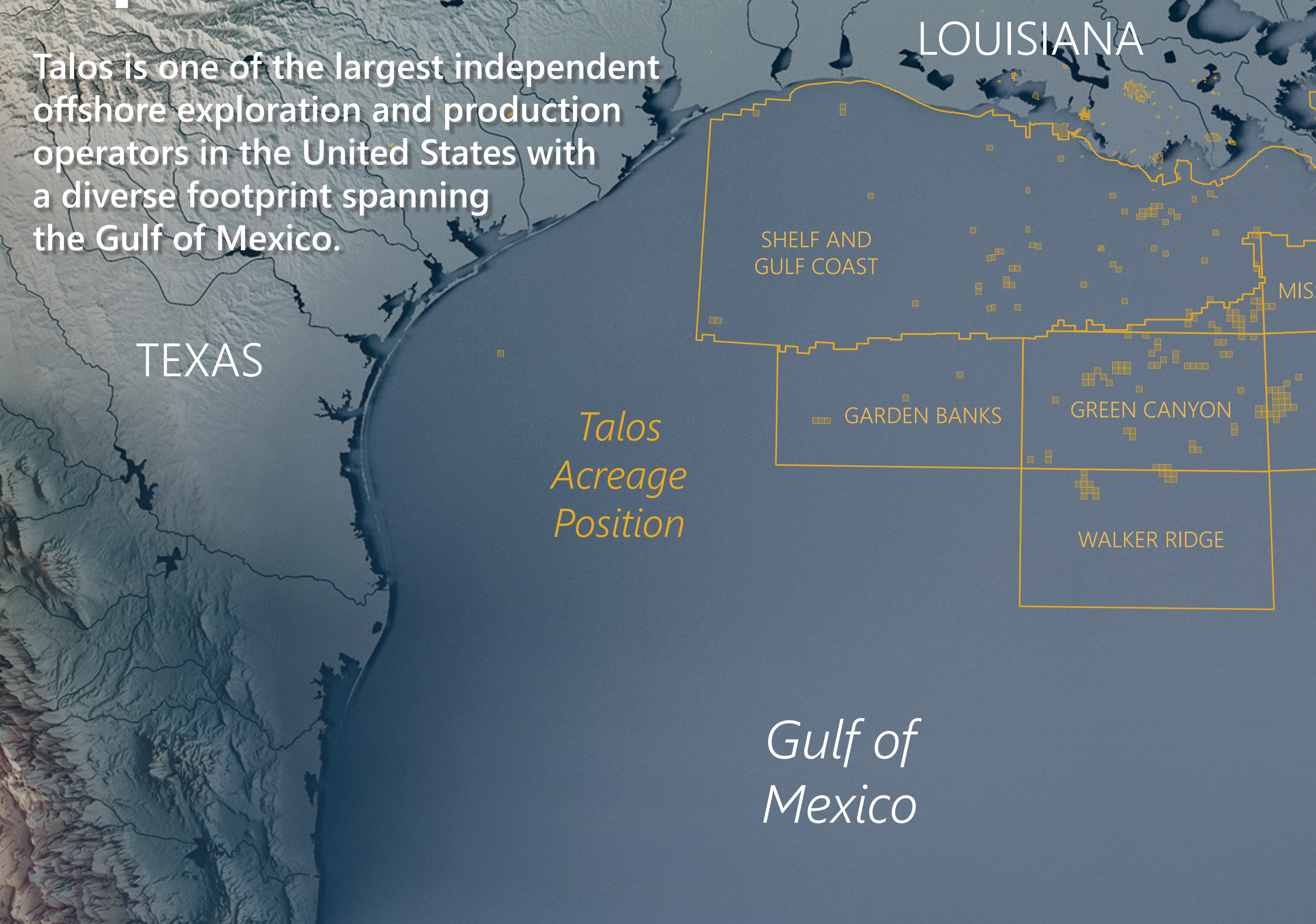
The Company has announced four CCS projects representing one of the largest sequestration footprints in the United States, supporting 1.6 billion tons of gross capacity across about 250,000 gross acres in key industrial epicenters along the Gulf Coast.

These complementary businesses uniquely position Talos to contribute to global prosperity through energy security today while also playing a leading role in decarbonization efforts for the future.

NYSE: TALO

Upstream Asset Overview

Talos is one of the largest independent offshore exploration and production operators in the United States with a diverse footprint spanning the Gulf of Mexico.



Key Talos Facilities

RAM POWELL

PHOENIX COMPLEX

AMBERJACK

POMPANO

GREEN CANYON 18

OFFSHORE MEXICO

Zama
Discovery

Mississippi Canyon Area – A prolific production area in the eastern portion of the Central Gulf of Mexico where we continue unlocking new resources. In this region, Talos operates four production facilities and acts as both an operator and a non-operating partner in numerous development projects and producing fields.

Green Canyon Area – A key deepwater focus area for our exploration activities in the Central Gulf, where we operate six production facilities, including a floating production unit, the Helix Producer I (HP-I).

Shelf and Gulf Coast – The U.S. Shelf and Gulf Coast area spans the basin and provides diverse production from multiple facilities. The Shelf area is a mature production region with redevelopment, recovery enhancement, and exploration opportunities.

Offshore Mexico – Offshore activities in Mexico are in the Sureste basin, a proven shallow water province off the coast of Mexico's Veracruz and Tabasco states. Our recent Mexico discoveries include one of the world's largest shallow water oil discoveries in 2017 called Zama.


BRUTUS/ GLIDER


PRINCE


LOBSTER


COGNAC


NEPTUNE

Letter to Shareholders

APRIL 2023

2022 was an outstanding year for Talos, with numerous milestones across our Upstream and Carbon Capture and Sequestration ("CCS") businesses. Our employees delivered some of their best results ever with an ongoing emphasis on safety, environmental responsibility, and contributions to local communities, positioning us to enhance long-term value creation for our shareholders.

IN 2022, we attained record-setting financial performance, completed a major acquisition, and grew our CCS business to one of the largest carbon storage portfolios in the United States. Our operational achievements drove strong adjusted free cash flow generation while achieving a strong credit profile with solid liquidity and low leverage.

Conventional Offshore Exploration Expertise

In our Upstream business, on a pro forma basis for the EnVen transaction, we ended 2022 with a larger, more diverse, and more liquids-weighted reserve base. Looking at our ongoing drilling program, we drilled six successful development and exploitation wells. These discoveries will significantly impact our production growth over the next 18 months. Our success is based on our deep in-house technical and operational expertise focused on applying the latest technology and processes to optimize projects across our portfolio while leveraging the infrastructure we own or acquire through active business development.

Trusted Counterparty in the Gulf of Mexico

Talos's demonstrated ability to productively leverage existing infrastructure also reinforces the strategic merits of our acquisition of EnVen, which closed in February 2023. This strategic transaction adds scale and diversity with high margin, oil-weighted assets, and ample infrastructure.

The transaction also enhances our adjusted free cash flow generation ability, is attractive to Talos shareholders, and further improves our outstanding credit position. The integration of our companies is on track as we work to realize the valuable synergies we expect to generate from the combination.

With the EnVen acquisition, Talos is better positioned to accelerate organic, value-creating activities through both our Upstream and CCS businesses as well as subsequent M&A and business development activities.

U.S. Gulf Coast Leading CCS Portfolio

In our CCS business, we continue to develop and expand our efforts with Talos Low Carbon Solutions. Since its inception in 2021, we have been busy developing our carbon storage portfolio, enhancing partnerships in core project areas across the U.S. Gulf Coast, and continuing productive conversations with industrial emitters. Over the last year, we moved into two new markets in the Mississippi River and Corpus Christi industrial corridors with our Coastal Bend and River Bend CCS projects, respectively. In addition, we expanded our partnership for the Bayou Bend CCS project with the addition of Chevron, which enhances the project's impact as a CCS hub serving industrial emitters. Most recently, our Bayou Bend CCS project increased its CO_2 storage footprint and now encompasses nearly 140,000 gross acres of pore space for permanent CO_2 sequestration. Expanding Bayou Bend creates a critical CCS hub well-positioned to support large-scale carbon removal and reduction projects across a broad industrial region of the Gulf Coast.

> "At Talos, we are committed to building a sustainable company where we can be a part of the entire energy ecosystem and proudly provide energy solutions that are critical to modern society, including conventional resources and carbon management solutions."

Timothy Duncan, President and Chief Executive Officer

Letter to Shareholders

(CONTINUED)

Today Talos's four CCS projects make up one of the largest sequestration portfolios in the U.S., supporting 1.6 billion tons of gross capacity across approximately 250,000 gross acres in key industrial epicenters. We are proud to be a part of the broader ecosystem of the energy complex and look forward to further advancing our CCS leadership position, which we believe will positively impact the environment for decades.

Capital Allocation Framework

Our top priorities continue to be adjusted free cash flow generation and debt repayment while exercising strategic discipline with opportunities we pursue across our key catalysts. In addition, as part of our commitment to returning capital to shareholders, we announced in March 2023 our first-ever share repurchase program.

Safety and Environmental Responsibility

At Talos, we practice a shared set of values, including our commitment to being responsible, ethical, and safe in everything we do. In 2022, we achieved the lowest Total Recordable Incident Rate in the Company's history. We are also pleased that 2022 was another historic year for maintaining a zero Lost Time Incident Rate.

TIMOTHY DUNCAN
TALOS ENERGY CEO

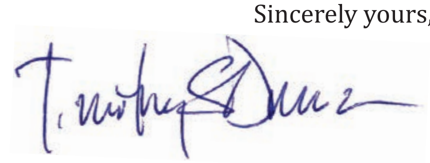
Likewise, we strive to safely and responsibly develop energy resources while minimizing our environmental impact. In 2022, we reduced our Scope I greenhouse gas emissions intensity by 30% from the Company's 2018 baseline year, achieving our initial goal three years sooner on a pro forma basis, including the EnVen assets. In addition, we recorded another year with zero hydrocarbon releases offshore greater than one barrel. The support we provide to the local communities where we live and work is another area rooted deeply in our values. We are proud of our people and recognize that the Company's robust performance stems from our employees' unwavering ingenuity and hard work. In 2022, we were pleased to again be named as a Top Workplace by the Houston Chronicle for the tenth consecutive year.

Outlook for Talos

The past year was a busy and successful year for Talos. In 2023 and beyond, we are excited about the expected growth in our Upstream business and the advancements in our maturing CCS business. Considering our recent successes in our drilling program, most of which are anticipated to come online during 2023 and 2024, combined with our positive outlook on several drilling projects planned during 2023, we expect our production to grow materially over the next three years while maintaining a healthy reinvestment rate and generating substantial adjusted free cash flow.

At Talos, we are committed to building a sustainable company where we can be a part of the entire energy ecosystem and proudly provide energy solutions that are critical to modern society, including conventional resources and carbon management solutions.

Sincerely yours,



Timothy S. Duncan
President and Chief Executive Officer

Financial Profile

2018 - 2022 FISCAL YEARS

Year Ended (Millions)	2022	2021	2020	2019	2018
Total Revenues	$1,652	$1,245	$576	$908	$891
Net Income (Loss)	$382	($183)	($466)	$59	$222
Capital Expenditures(1)	$456	$339	$406	$546	$391
Total Long-term Debt(2)	$804	$1,071	$1,055	$826	$766
Reserves(3) (MMBoe)					
Proved Developed Producing (PDP)	109	96	90	68	78
Proved Developed Non-Producing (PDNP)	47	41	37	30	38
Proved Developed	156	136	127	98	116
Proved Undeveloped (PUD)	34	25	36	44	36
Total Proved	**190**	**162**	**163**	**142**	**152**
Production					
Sales Volume (MMBoe)	21.7	23.5	20.0	19.0	16.7
Average Daily Production (MBoe/d)	59.5	64.4	54.7	52.0	45.9

"Talos is focused on maximizing shareholder value through disciplined investments, healthy credit, and responsible risk management."

Shane Young, Executive Vice President and Chief Financial Officer

(1) Includes plugging and abandonment and decommissioning obligations settled.
(2) Includes finance lease and excludes original issue discounts and deferred financing costs.
(3) All reserves prices at year-end SEC prices of $94.14/bbl WTI and $6.36/mcf HH, $67.14/$3.71, $39.47/$1.97, $61.01/$2.59, $69.42/$3.08, for 2022, 2021, 2020, 2019, and 2018, respectively. This table summarizes year end 2022 reserves of each of Talos and EnVen collectively. The proved undeveloped reserves of EnVen are based on EnVen's development plans and NSAI's reserve estimation methodologies. Because Talos will develop such proved undeveloped reserves in accordance with its own development plan and, in the future, will estimate proved undeveloped reserves in accordance with its own methodologies, the estimates presented herein may not be representative of Talos's future reserve estimates with respect to these properties or the reserve estimates Talos would have reported if it had owned such properties of EnVen as of December 31, 2022. Reserve numbers may not sum due to rounding.

Building the Energy Company of Tomorrow

LEVERAGING OUR UNIQUE CAPABILITIES FOR THE ENERGY TRANSITION

GROWTH IN UPSTREAM

Providing safe and responsible conventional energy resources for today and tomorrow

ADVANCEMENT OF CCS

Pursuing large-scale decarbonization solutions to reduce industrial emissions

A COMPLETE ENERGY COMPANY

Producing the energy needed today and advancing low carbon solutions for tomorrow

Growth in Upstream

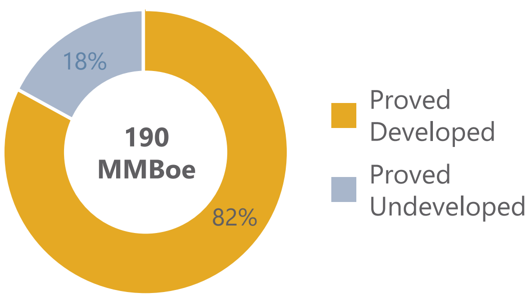
EXPANDING AND HIGH-GRADING INVENTORY FOR LONG-TERM GROWTH

"Talos Energy provides safe and responsible conventional energy resources for today and tomorrow."

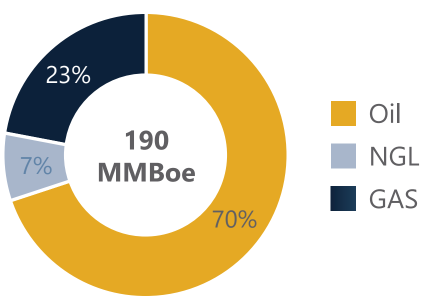
John Parker, Founder, Executive Vice President – New Ventures

Talos is one of the largest independent offshore exploration and production operators in the United States with a diverse footprint spanning the Gulf of Mexico.

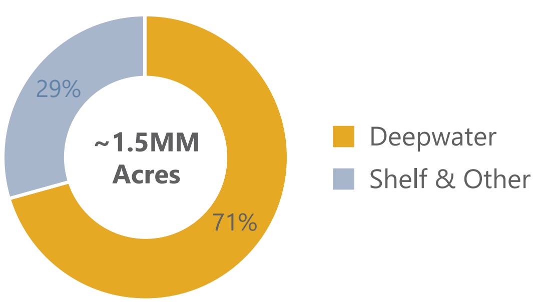
Proved Reserves by Category



Reserves by Commodity



Deepwater Footprint



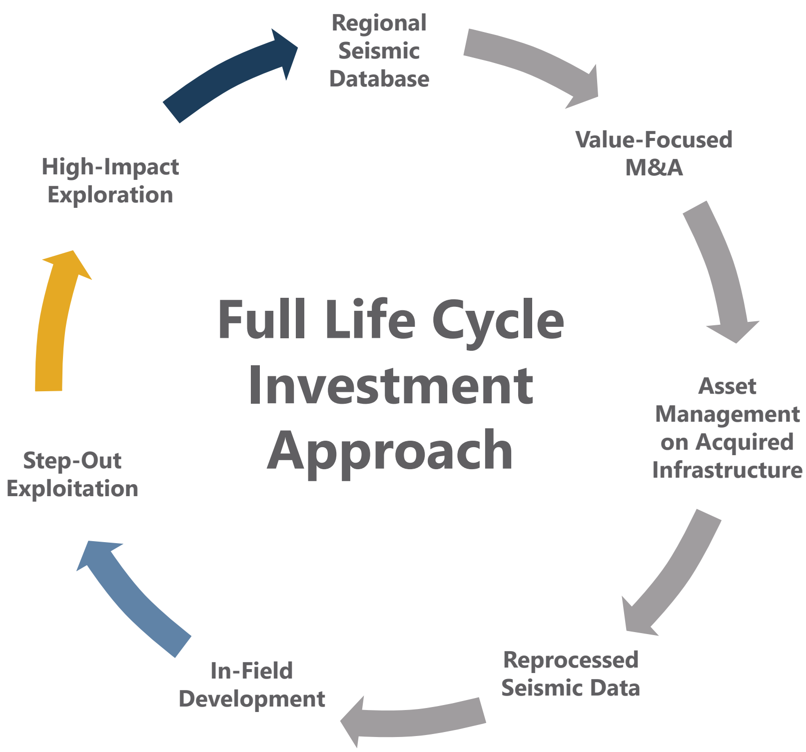
Today, Talos has a larger, more diverse asset base driving growth and free cash flow generation. Our unique portfolio of catalysts guides future value creation across our Upstream and leading CCS businesses.

Reserves figures are presented inclusive of the plugging and abandonment obligations and before hedges, utilizing SEC pricing of $94.14 WTI per Bbl of oil and $6.36 HH per Mcf of natural gas. Acreage figures as of December 31, 2022, excluding CCS and pro forma for EnVen. Year-end 2022 reserves for Talos and EnVen are represented collectively.

Growth in Upstream

OFFSHORE GULF OF MEXICO IS A SIGNIFICANT NATURAL RESOURCE

Talos is a logical partner in the Gulf of Mexico.



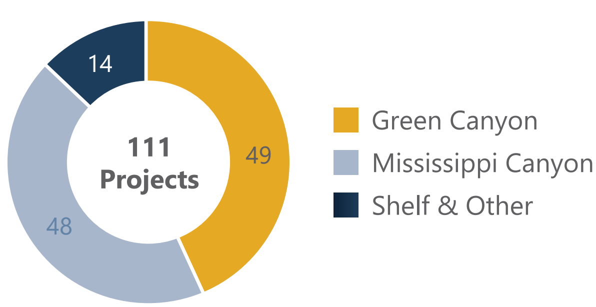
We closed the EnVen acquisition in mid-February 2023. The transaction expands our Gulf of Mexico operational scale and asset diversity on attractive financial terms.

- Increases Scale and Diversity
- Accretive to Talos Shareholders
- Credit Enhancing
- Heightened Governance

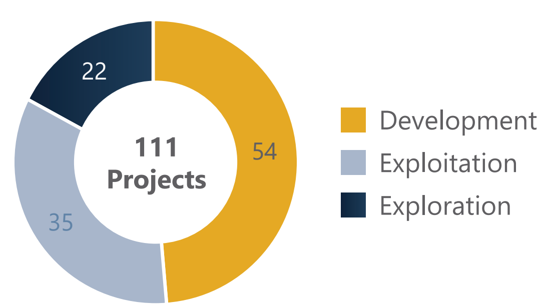
Our strategic focus is on long-term value creation through the acquisition and development of conventional resources near under-utilized infrastructure applying Talos's vast seismic inventory and advanced reprocessing to build value through drilling opportunities across the full asset life cycle.

Talos has a large inventory of projects that can support years of prospective growth.

Projects by Core Area



Projects by Type



Inventory figures as of December 31, 2022 pro forma for EnVen.

Advancement of CCS

UNIQUELY POSITIONED TO BE A LEADER IN INDUSTRIAL DECARBONIZATION

"TLCS has four CCS projects supporting 1.6 billion tons of gross capacity across ~250,000 gross acres in key industrial epicenters."

Robin Fielder, Executive Vice President – Low Carbon Strategy and Chief Sustainability Officer

Our CCS business operates through our Talos Low Carbon Solutions ("TLCS") subsidiary. Conventional reservoir expertise and operational capabilities will position Talos to be a leading CCS player.

Talos is uniquely positioned to leverage its existing in-house experience with its conventional geology and technical expertise along the Gulf Coast toward growing a complementary business portfolio of decarbonization projects. Our CCS projects can assist industrial partners with carbon emissions capture, transportation, and injection into sequestration sites that we believe will positively impact the environment for decades.

Talos aims to be a recognized leader in domestic decarbonization focused on delivering safe, reliable, and cost-effective solutions to create sustainable value for our stakeholders.

The priorities for TLCS going forward are to continue expanding and advancing our industry-leading portfolio of CCS opportunities along the Gulf Coast. Near term, this includes executing CO_2 offtake contracts, expanding partnerships in existing projects, progressing the permitting of Front-End Engineering Design workstreams, and developing additional point source projects. Point source projects are customized sequestration projects for industrial partners to capture and eliminate carbon emissions from singular sources, such as liquefied natural gas facilities, manufacturing plants or power generation facilities, among others.

Talos Energy is pursuing large-scale decarbonization solutions to reduce industrial emissions.

The Four Pillars of the Talos Low Carbon Solutions Strategy

1. **Calculated Speed –** Maintaining first mover advantage while scaling wisely
2. **Partner of Choice –** Meeting stakeholder needs with bespoke decarbonization solutions
3. **Operational Assurance –** Minimizing customer and environmental risk
4. **Investable Value –** Building long-term value by delivering a high-quality project portfolio

Advancement of CCS

A MATURING PORTFOLIO OF FOUR PROJECTS ACROSS THE U.S. GULF COAST

CCS Hub Projects

BAYOU BEND CCS

Industrial Region: Houston Ship Channel and Beaumont / Port Arthur, Texas
Regional CO_2 Emissions: ~80 MTPA
Project Site: ~140,000 Gross Acres Onshore, Offshore
Gross Storage Capacity: >1,000+ MM MT CO_2

RIVER BEND CCS

Industrial Region: New Orleans / Baton Rouge, Louisiana
Regional CO_2 Emissions: ~80 MTPA
Project Site: ~89,000 Gross Acres[(1)] Onshore
Gross Storage Capacity: 500+ MM MT CO_2

CCS Point Source Projects

FREEPORT LNG CCS

Industrial Region: Brazoria County, Texas
Regional CO_2 Emissions: ~20 MTPA
Project Site: ~500 Gross Acres Onshore
Gross Storage Capacity: ~25 MM MT CO_2

COASTAL BEND CCS

Industrial Region: Corpus Christi, Texas
Regional CO_2 Emissions: ~20 MTPA
Project Site: 13,000 Gross Acres Onshore
Gross Storage Capacity: 50-100+ MM MT CO_2

(1) Includes ~63,000 acres on right of first refusal in addition to leased 26,000 acres.

A Complete Energy Company

STRIVING FOR ZERO INCIDENTS

Talos aims to conduct our business in a way that ensures safety, minimizes environmental impacts, positively influences our local communities, and prioritizes ethics and good governance.

Safety and Environmental Performance

Talos is highly focused on conducting our business in a manner that prioritizes the safety, health, and well-being of all personnel, including employees, contractors, and partners, as well as the communities in which we work. We take great pride in creating a safe working environment and maintaining a leadership position among peers with key safety performance indicators.

In 2022, we achieved the lowest Total Recordable Incident Rate in the Company's history, well below the average for Gulf of Mexico operators. We also maintained a zero Lost Time Incident Rate. In addition, Talos recorded another year of zero hydrocarbon releases offshore greater than one barrel while operating over 21 million barrels of oil equivalent.

30% Reduction in GHG Intensity[1]

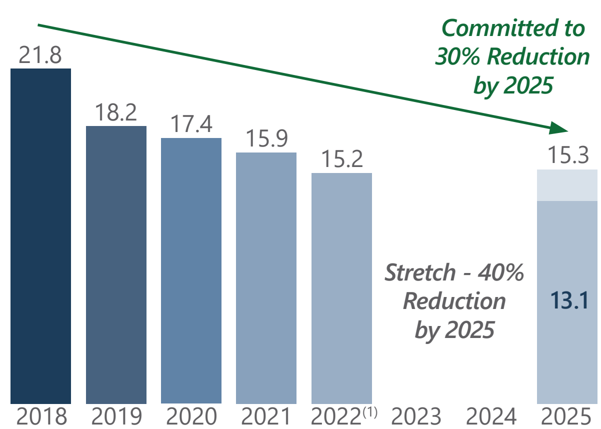
ZERO Offshore Spills >1 Barrel in Size

ZERO 2022 Lost Time Injury Rate

Environmental responsibility is also critically important to Talos. We are actively taking steps to reduce our greenhouse gas ("GHG") emissions over time and have steadily reduced Scope 1 emissions intensity from our operations. In 2022, we reduced our Scope 1 GHG emissions intensity by 30% from the Company's 2018 baseline year, achieving our initial goal three years sooner on a pro forma basis, including the EnVen assets.

Driving Down Environmental Emissions[1]

(Gross Operated Prod., MT CO_2 Equivalent/MBoe)



(1) Scope 1 GHG emissions intensity data only combined in 2022, pro forma for EnVen. 2018-2021 are Talos emissions only.

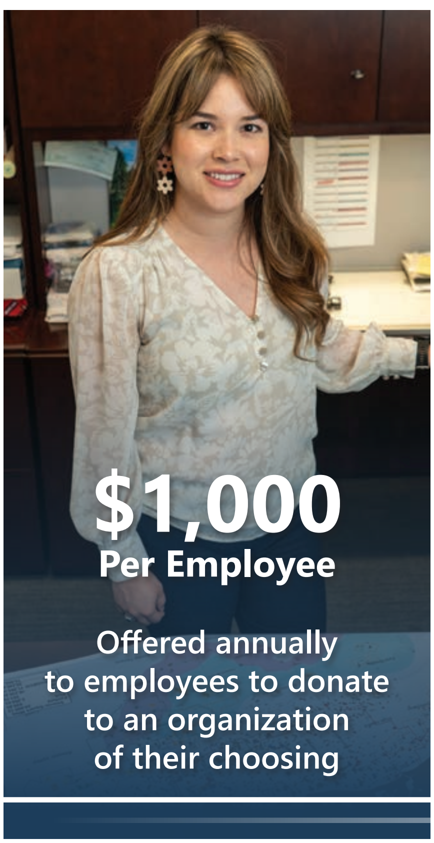
Culture and Community

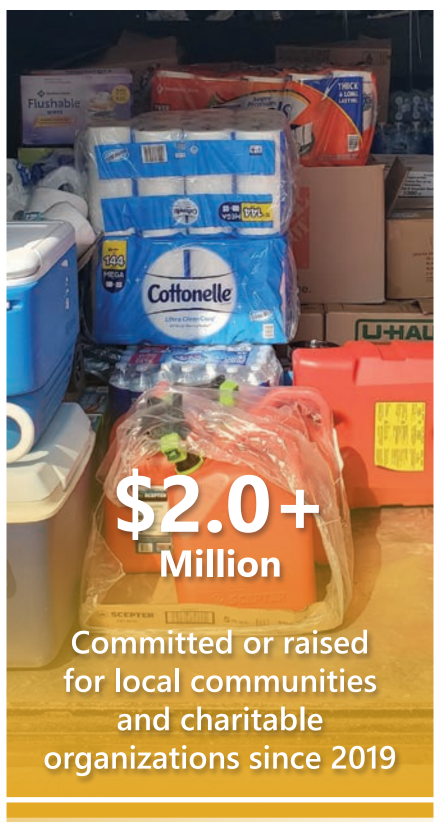
Talos aims to be a highly supportive partner of our employees, their careers, their families, and the broader communities where they work and live. We actively support numerous organizations and are consistently named one of the Top Workplaces in Houston by the Houston Chronicle.

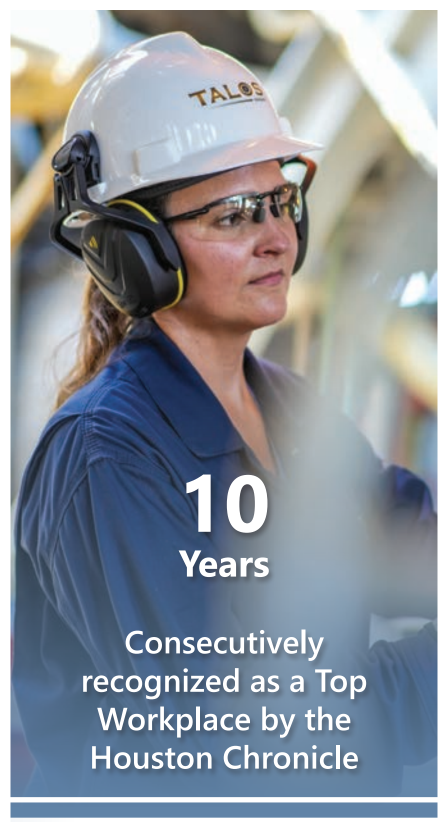
Our people are our most valuable resource. We support our employees with a comprehensive benefits package, flexible schedules, and career growth and development opportunities. We also value the diversity of our employees and are committed to an inclusive, equitable culture to ensure employees feel heard and have a sense of belonging.

In the communities where we live and work, we are actively engaged in outreach, charitable fundraising, and education and awareness. Since 2019, we have committed and raised over $2 million. In 2023, we doubled the amount from $500 to $1,000 annually that we provide to our employees to donate to charitable organizations of their choice.

We are honored to be named as a Top Workplace in Houston by the Houston Chronicle for ten consecutive years, and we have our employees to thank for it. Talos employees are committed to living our values every day, representing our core culture: Think as an Owner, Embody Integrity & Safety, Maintain Optionality, Empower Each Other, and Embrace Diversity and Inclusion.








SEATRAX
TALOS ENERGY

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2022

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 001-38497

Talos Energy Inc.
(Exact name of Registrant as specified in its Charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**82-3532642** **(I.R.S. Employer Identification No.)**
333 Clay Street, Suite 3300 **Houston, TX** **(Address of principal executive offices)**	**77002** **(Zip Code)**

Registrant's telephone number, including area code: (713) 328-3000

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock	TALO	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☑

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☑	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on the closing price of the shares of common stock on the New York Stock Exchange on June 30, 2022, was $1,076,771,374.

The number of shares of registrant's Common Stock outstanding as of February 21, 2023 was 126,370,218.

Portions of the registrant's definitive proxy statement relating to the 2023 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

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GLOSSARY

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

***Barrel or Bbl* —** One stock tank barrel, or 42 United States gallons liquid volume.

***Boe* —** One barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of crude oil or condensate.

BOEM — Bureau of Ocean Energy Management.

BSEE — Bureau of Safety and Environmental Enforcement.

***Boepd* —** Barrels of oil equivalent per day.

***Btu* —** British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water one degree Fahrenheit.

CO_2 — Carbon dioxide.

***Completion* —** The installation of permanent equipment for the production of oil or natural gas.

***Deepwater* —** Water depths of more than 600 feet.

***Developed acres* —** The number of acres that are allocated or assignable to producing wells or wells capable of production.

***Field* —** An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition.

***GAAP* —** Accounting principles generally accepted in the United States of America.

***Gross acres or gross wells* —** The total acres or wells in which the Company owns a working interest.

***MBbls* —** One thousand barrels of crude oil or other liquid hydrocarbons.

***MBblpd* —** One thousand barrels of crude oil or other liquid hydrocarbons per day.

***MBoe* —** One thousand barrels of oil equivalent.

***MBoepd* —** One thousand barrels of oil equivalent per day.

***Mcf* —** One thousand cubic feet of natural gas.

***Mcfpd* —** One thousand cubic feet of natural gas per day.

***MMBoe* —** One million barrels of oil equivalent.

***MMBtu* —** One million British thermal units.

***MMcf* —** One million cubic feet of natural gas.

***MMcfpd* —** One million cubic feet of natural gas per day.

***Net acres or net wells* —** The sum of the fractional working interests the Company owns in gross acres or gross wells.

***NGL* —** Natural gas liquid. Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane and natural gasoline.

***NYMEX* —** The New York Mercantile Exchange.

***NYMEX Henry Hub* —** Henry Hub is the major exchange for pricing natural gas futures on the New York Mercantile Exchange. It is frequently referred to as the Henry Hub Index.

***OPEC* —** Organization of Petroleum Exporting Countries.

***Productive well* —** A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

***Proved developed reserves* —** In general, proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

***Proved reserves* —** Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

***Proved undeveloped reserves* —** In general, proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

***PV-10* —** The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) non-property related expenses such as general and administrative expenses, derivatives, debt service and future income tax expense or (ii) depreciation depletion and amortization expense.

***SEC* —** The Securities and Exchange Commission.

***SEC pricing* —** The unweighted average first-day-of-the-month commodity price for crude oil or natural gas for each month within the 12-month period prior to the end of the reporting period, adjusted by lease for market differentials (quality, transportation, fees, energy content, and regional price differentials). The SEC provides a complete definition of prices in "Modernization of Oil and Gas Reporting" (Final Rule, Release Nos. 33-8995; 34-59192).

***Shelf* —** Water depths up to 600 feet.

***Standardized Measure* —** The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules, regulations or standards established by the SEC and the Financial Accounting Standards Board (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

***Undeveloped acreage* —** Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves.

***Working interest* —** The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

***WTI or West Texas Intermediate* —** A light crude oil produced in the United States with an American Petroleum Institute gravity of approximately 38-40 and the sulfur content is approximately 0.3%.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this Annual Report on Form 10-K (this "Annual Report") includes "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 (the "Exchange Act"). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project," "forecast," "may," "objective," "plan," and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. Forward-looking statements may include statements about:

- business strategy;
- reserves;
- exploration and development drilling prospects, inventories, projects and programs;
- our ability to replace the reserves that we produce through drilling and property acquisitions;
- financial strategy, liquidity and capital required for our development program and other capital expenditures;
- realized oil and natural gas prices;
- the transaction with EnVen Energy Corporation ("EnVen", and such transaction, the "EnVen Acquisition") and anticipated future performance of the combined company;
- timing and amount of future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- future drilling plans;
- availability of pipeline connections on economic terms;
- competition, government regulations and political developments;
- our ability to obtain permits and governmental approvals;
- pending legal, governmental or environmental matters;
- our marketing of oil, natural gas and NGLs;
- leasehold or business acquisitions on desired terms;
- costs of developing properties;
- general economic conditions, including the impact of continued inflation and associated changes in monetary policy;
- political and economic conditions and events in foreign oil, natural gas and NGL producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, the war in Ukraine and associated economic sanctions on Russia, conditions in South America, Central America and China and acts of terrorism or sabotage;
- credit markets;
- impact of new accounting pronouncements on earnings in future periods;
- estimates of future income taxes;

- our estimates and forecasts of the timing, number, profitability and other results of wells we expect to drill and other exploration activities;
- the success of our carbon capture and sequestration opportunities;
- our ongoing strategy with respect to our Zama asset;
- uncertainty regarding our future operating results and our future revenues and expenses; and
- plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to numerous risks and uncertainties, most of which are difficult to predict and many of which are beyond our control. These risks include, but are not limited to, commodity price volatility due to the continued impact of the coronavirus disease 2019 ("COVID-19"), including any new strains or variants, and governmental measures related thereto on global demand for oil and natural gas and on the operations of our business; the ability or willingness of OPEC and other state-controlled oil companies ("OPEC Plus"), such as Saudi Arabia and Russia, to set and maintain oil production levels; the impact of any such actions; the lack of a resolution to the war in Ukraine and its impact on certain commodity markets; lack of transportation and storage capacity as a result of oversupply, government and regulations; lack of availability of drilling and production equipment and services; adverse weather events, including tropical storms, hurricanes and winter storms; cybersecurity threats; sustained inflation and the impact of central bank policy in response thereto; environmental risks; failure to find, acquire or gain access to other discoveries and prospects or to successfully develop and produce from our current discoveries and prospects; geologic risk; drilling and other operating risks; well control risk; regulatory changes; the uncertainty inherent in estimating reserves and in projecting future rates of production; cash flow and access to capital; the timing of development expenditures; potential adverse reactions or competitive responses to our acquisitions and other transactions; the possibility that the anticipated benefits of our acquisitions are not realized when expected or at all, including as a result of the impact of, or problems arising from, the integration of acquired assets and operations, and the other risks discussed in Part I, Item 1A. Risk Factors which are included herein.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas and NGLs 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 reserve engineers. In addition, the results of drilling, testing and production activities may justify upward or downward revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Should one or more of the risks or uncertainties described herein occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

SUMMARY RISK FACTORS

Risks Related to our Business and the Oil and Natural Gas Industry

- Oil and natural gas prices are volatile. Stagnation or declines in commodity prices may adversely affect our financial condition and results of operations, cash flows, access to the capital markets and ability to grow.
- Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.
- Production periods or relatively short reserve lives for U.S. Gulf of Mexico properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.
- Our actual recovery of reserves may substantially differ from our proved reserve estimates.
- Our acreage has to be drilled before lease expirations in order to hold the acreage by production. If commodity prices become depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.
- The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.
- Lower oil and natural gas prices and other factors in the future may result in ceiling test write-downs and other impairments of our asset carrying values.
- Continuing or worsening inflationary issues and associated changes in monetary policy may result in increases to the cost of our goods, services and personnel, which in turn could cause our capital expenditures and operating costs to rise.
- We may be unable to pursue our CCS business, either wholly or in significant measure, which could have a material adverse effect on our business, results of operations and financial condition.
- Our inability to qualify for, obtain, monetize or otherwise benefit from Section 45Q tax credits could materially reduce our ability to develop CCS projects and, as a result, may adversely impact our business, results of operations and financial condition.
- Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.
- Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.
- The ongoing war between Russia and Ukraine could adversely affect our business, financial condition and results of operations.
- New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.
- We may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves from our non-operated properties.
- Hedging transactions may limit our potential gains.
- Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine mammals and endangered and threatened species.

- We may be unable to provide the financial assurances in the amounts and under the time periods required by the BOEM if it submits future demands to cover our decommissioning obligations. If in the future the BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.
- Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local governmental regulations that materially affect our operations.
- If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.
- Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.
- We may experience significant shut-ins and losses of production due to the effects of tropical storms and hurricanes in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico.
- The Inflation Reduction Act of 2022 could accelerate the transition to a low carbon economy and could impose new costs on our operations.

Risks Related to our Capital Structure and Ownership of our Common Stock

- Our debt level and the covenants in our current or future agreements governing our debt, including our Bank Credit Facility and the indenture for our 12.00% Second-Priority Senior Secured Notes, could negatively impact our financial condition, results of operations and business prospects. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.
- A financial crisis may impact our business and financial condition and may adversely impact our ability to obtain funding under our Bank Credit Facility or in the capital markets.
- We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.
- We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. Accordingly, we are dependent upon distributions from Talos Production Inc. to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock.
- Our estimates of future asset retirement obligations may vary significantly from period to period and unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.
- We may not realize all of the anticipated benefits from our future acquisitions, and we may be unable to successfully integrate future acquisitions.
- Our future acquisitions could expose us to potentially significant liabilities, including P&A liabilities.
- Resolution of litigation could materially affect our financial position and results of operations.

Risks Related to our Integration of EnVen into our Business

- The combined company may fail to realize the anticipated benefits of the EnVen Acquisition.
- The failure to successfully integrate our business and operations with EnVen in the expected time frame may adversely affect our future results.

PART I

Items 1 and 2. Business and Properties

Overview

As used in this Annual Report and unless otherwise indicated or the context otherwise requires, references to "we," "us," "our," "Talos Energy Inc.," "Talos" and the "Company" refer to Talos Energy Inc. and its consolidated subsidiaries.

We were incorporated on November 14, 2017 under the laws of the state of Delaware for the purpose of effecting the business combination between Talos Energy LLC and Stone Energy Corporation ("Stone"), pursuant to which each of Talos Energy LLC and Stone became our wholly-owned subsidiary.

We are a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through our operations, currently in the United States ("U.S.") and offshore Mexico both through oil and gas exploration and production ("Upstream") and the development of carbon capture and sequestration ("CCS") opportunities. We leverage decades of technical and offshore operational expertise in the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. With a focus on environmental stewardship, we also utilize our expertise to explore opportunities to reduce industrial emissions through our CCS initiatives along the coast of the U.S. Gulf of Mexico ("Gulf Coast").

We combine our technical experience in geology, geophysics and engineering with innovative resource evaluation techniques and seismic imaging expertise to discover new resources. We rely on our operational experience to optimize our assets' production and recovery safely and responsibly. Finally, we leverage our commercial and corporate management experience to most effectively allocate our capital to balance risk and reward, grow our business and maximize long-term stockholder value.

Business Strategy

We intend to increase stockholder value by growing our Upstream reserves, production, cash flow and future growth opportunities in a capital efficient manner while exploring potential CCS opportunities with aspirations to become a contributor to U.S. emissions reduction goals. Our deep technical expertise and extensive physical operating experience also allows us to successfully manage our Upstream business and consistently make attractive acquisitions, thereby increasing stockholder value over time. Additionally, we believe these same core competencies can be utilized to develop large-scale decarbonization projects to reduce industrial emissions.

Upstream Strategy

We maintain a large and diverse in-house technical staff focused on geology, geophysics, engineering and other technical disciplines, providing many decades of exploration and production experience in the key resource trends in which we focus. Our significant library of seismic data resources, which focuses on the U.S. Gulf of Mexico and offshore Mexico, allows our technical team to apply proprietary seismic reprocessing techniques to evaluate or re-evaluate potential resources across our asset portfolio. Finally, we have deep in-house experience across our offshore operations, production operations, safety, facilities and business development teams.

Our strategic business development activities allow us to consistently identify and evaluate new opportunities through a wide range of potential avenues, including government lease sales, joint ventures and acquisitions, among others. Our proven track record of success through organic drilling opportunities frequently attracts potential drilling partners in projects that we operate, while in non-operated projects we leverage our core competencies to independently identify the best investment opportunities, review partner-proposed projects and be a value-added contributor. Our asset acquisition strategy is focused on assets with a geological setting that can benefit from our ability to use our seismic database and technical expertise to re-evaluate and improve the acquired properties. Specifically, our acquisition focus areas target a variety of potential situations and sellers that are currently available in offshore basins, including single asset acquisitions, consolidation of private companies and broader asset package transactions. We seek to actively participate in government lease sales to identify and acquire attractive leasehold acreage, which in many cases has not been evaluated with the latest reprocessed seismic data, resulting in an opportunity for us to identify previously unknown drilling prospects.

We have historically focused our operations in the U.S. Gulf of Mexico because of our deep experience and technical expertise in the basin, which maintains favorable geologic and economic conditions, including multiple reservoir formations, comprehensive geologic and geophysical databases, extensive infrastructure and an attractive asset acquisition market. Our asset footprint, which includes operational control of several key shallow and Deepwater facilities, allows us to invest in a diverse set of opportunities ranging from in-field development to high impact exploration projects while optimizing our facilities to lower incremental operating costs structures. We also believe our operated infrastructure can be attractive to other operators looking for a host facility for their subsea tie-back projects, which allows us either to be involved in new investment opportunities or to offset the operating cost of these facilities.

Utilizing our core competencies in conjunction with a robust and active business development effort allows us to use the following strategies to increase stockholder value:

- ***Continuously Optimizing our Existing Asset Base —*** We benefit from our proven ability to enhance and extend the life of existing projects within our portfolio. Investments in optimization projects across our asset base aim to stabilize and improve the profile of producing assets by increasing recovery, production and cash flow with typically relatively low investment capital and risk. These projects allow for reinvestment opportunities in exploitation and exploration projects.
- ***Conducting Development and Near-Field Projects In and Around Our Existing Asset Footprint —*** We undertake asset development and exploitation drilling projects in close proximity to our existing assets as well as facilities that we either own or have access to. These projects leverage ongoing operations and existing technical knowledge of the area, often coupled with recent proprietary seismic reprocessing evaluations to provide attractive incremental investment opportunities to grow reserves, production and cash flow in well-understood areas.
- ***Engaging in Exploration Activities to Grow our Asset Base and Potentially Unlock Significant New Resources —*** We conduct exploration drilling activities across our acreage set with risk-weighted investments that could establish significant new reserves and production. These projects are intended to optimize risk and reward across our portfolio of prospective drilling opportunities by finding and developing previously undiscovered resources along existing or emerging geological trends with the most efficient deployment of capital. When successful, exploration drilling activities can organically generate material new assets for the Company.
- ***Utilize Acquisitions and Other Business Development Activities to Expand our Asset Base, Opportunity Set and Value Creation Potential —*** We rely on our commercial and business development activities to expand our asset base through the acquisition or optimization of additional or existing properties, respectively. Commercial and business development provides a key avenue to create additional value from the acquisition of undervalued properties where we can apply our technical and operational competencies to generate upside. Additionally, we utilize business development to acquire new leaseholds, enter new projects and increase or decrease working interests in various existing projects to optimize capital planning and our targeted risk/return profile for varying business conditions. Acquisition opportunities in our basin and, more broadly, in the offshore exploration and production segment in other basins around the world, are numerous and span a wide range of lifecycle stages, sizes and geographic variables. We expect to continue utilizing acquisitions and business development to grow our business in a manner that preserves a strong and healthy credit profile as well as a diverse and high-quality asset base.

- ***Maintain Safety, Sustainability and Corporate Responsibility as Key Principles for Operations Across All Areas of our Business —*** We are focused on maintaining high standards of safety, environmental responsibility and corporate citizenship across all elements of our business. We closely monitor safety performance and consistently take steps to improve our performance. For the year ended 2022, we maintained a high level of safety performance with a lower recordable incident rate when compared to the average for offshore operators in the U.S. Gulf of Mexico as well as across numerous other industrial sectors of the broader economy. We strive to execute our business plan while simultaneously minimizing our environmental footprint, including emissions, potential spills and other impacts. Due to the nature of subsea wells and ample offshore pipelines, we believe the offshore operating environment is a region where greenhouse gas ("GHG") emissions can continue to be lowered over time. Finally, we aim to be a good corporate citizen in the regions and communities where we operate. We recently published our third annual Environmental, Social, and Governance ("ESG") report highlighting our performance and initiatives across all of these categories and other topics, which is not incorporated into, and does not form a part of, this Annual Report.

Carbon Capture and Sequestration Strategy

Our CCS business is operated through our Talos Low Carbon Solutions ("TLCS") subsidiary. TLCS intends to leverage its experience and technical expertise along the Gulf Coast, including subsurface engineering expertise, seismic data sets and interpretation capabilities, operational experience offshore and along the Gulf Coast and a solid track record of safety and environmentally responsible operations. The Gulf Coast is a critical industrial region with a large emissions footprint, while the underlying conventional geology in the area is believed to be ideal for carbon sequestration. TLCS intends to provide decarbonization solutions to assist industrial partners with carbon emissions capture, transportation and injection into sequestration sites in the region.

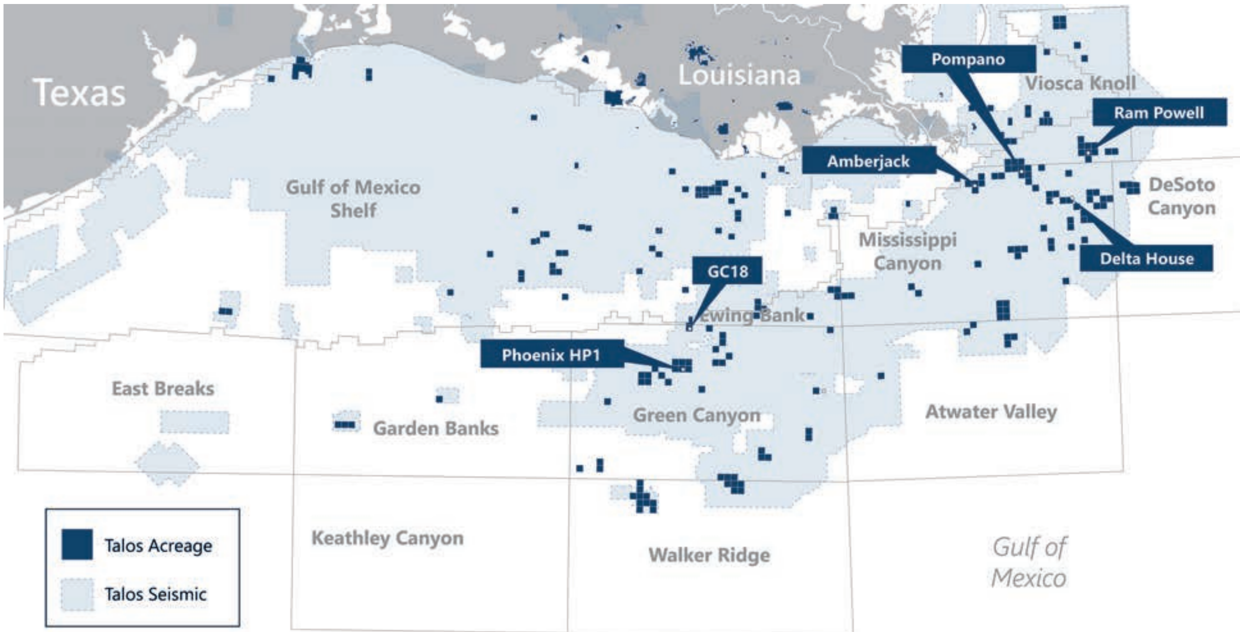
Upstream Properties

United States Gulf of Mexico

Our area of focus in the United States is the Gulf of Mexico Deepwater. Our strategy is concentrated in areas characterized by clearly defined infrastructure, well-known production history and geological well control, which reduces operational and investment risk. We believe the potential for large discoveries and increasing success rates in the sub-salt and mini-basin lower Pliocene and Miocene plays has resulted in increased industry focus on this area over the last decade.

We also believe our Deepwater operations in the U.S. Gulf of Mexico provide significant potential growth opportunities through our drilling program. Through our technical approach of starting with known hydrocarbon systems and applying modern seismic reprocessing techniques, we have generated a substantial inventory of Deepwater prospects that we believe are capable of delivering predictable production growth. We primarily focus our exploitation and exploration efforts around our existing infrastructure. This subsea tie-back strategy allows for better project economics and shorter periods between a discovery and production as compared to design, construction and installation of a new facility following a discovery.

As of December 31, 2022, our core areas in the United States are illustrated below:



The following table sets forth a summary of certain key 2022 information regarding our core areas in the United States:

	Estimated Proved Reserves						
	MBoe	% Oil	% Natural Gas	% NGLs	% Proved Developed	Net Production (MBoe)	% Operated
Green Canyon	30,691	81%	13%	6%	100%	6,731	97%
Mississippi Canyon	74,380	68%	21%	11%	76%	9,383	60%
Shelf & Gulf Coast	35,508	44%	48%	8%	82%	5,609	53%
Total United States	140,579	65%	26%	9%	83%	21,723	70%

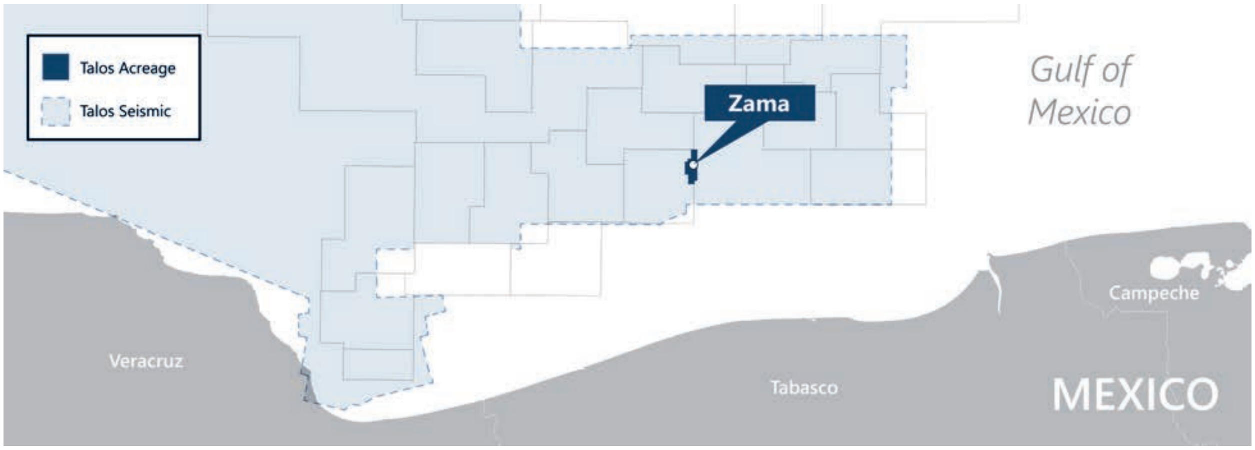
Green Canyon — Green Canyon is a Deepwater region in the Central U.S. Gulf of Mexico and is a key focus area both industry-wide and for our exploration activities. We operate two production facilities in the region, including a floating production unit, the Helix Producer I ("HP-I"), that is leased from Helix Energy Solutions Group, Inc. ("Helix").

Mississippi Canyon — Mississippi Canyon is a Deepwater region in the eastern portion of the Central U.S. Gulf of Mexico with a track record of prolific production and ongoing exploration success that continues to unlock new resources. We operate three production facilities in the region and are active as both an operator and non-operating partner in numerous development projects and producing fields.

Shelf and Gulf Coast — The U.S. Gulf of Mexico Shelf (the "Shelf") and Gulf Coast area spans an enormous geographical area across the basin and provides diverse production from numerous operated production facilities. The Shelf area is a producing region of the basin with attractive redevelopment and recovery enhancement opportunities.

Mexico

As of December 31, 2022, our area of focus in Mexico is the Block 7, Zama Unit Area segment located within the Sureste Basin, a prolific proven hydrocarbon province, in the shallow waters off the coast of Mexico's Tabasco state. Such area is illustrated below:



Block 7 — On July 15, 2015, a Talos-led consortium was awarded Block 7 ("Block 7 Consortium") with a term of thirty years, starting in September 2015, and extendable for two additional five-year periods. The Company's participation interest in Block 7 is 35% and we are the operator. The Block 7 Consortium made a significant discovery in Block 7 after drilling the Zama-1 in 2017, less than two years after signing a production sharing contract ("PSC") for the block with Mexico's upstream oil and gas regulator, the National Hydrocarbon Commission ("CNH"). Subsequent to the Zama-1 discovery, we drilled three additional wells to further appraise the discovery.

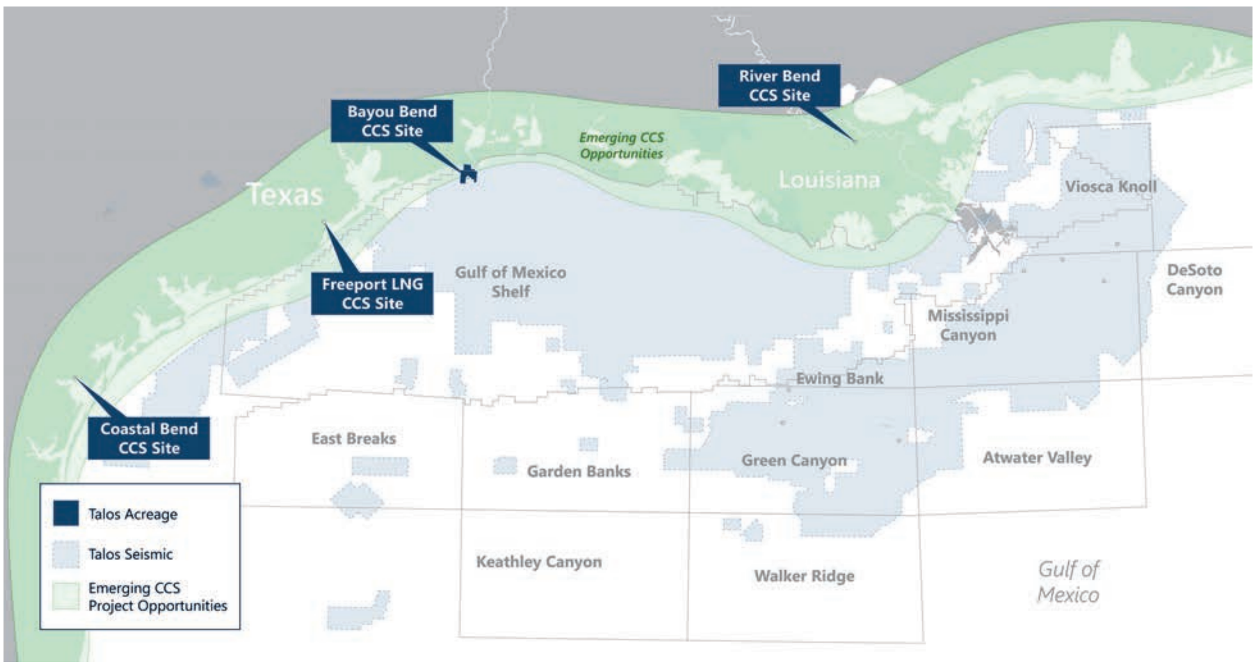
Upon conclusion of the three well appraisal program, we determined that the Zama Field likely extended into a nearby offshore block owned by Petróleos Mexicanos ("PEMEX"). On July 7, 2020, we received a notice from Mexico's Secretaría de Energía ("SENER") instructing the Block 7 Consortium and PEMEX to unitize the Zama Field. The Block 7 Consortium and PEMEX engaged a third-party reservoir engineering firm to evaluate initial tract participation within the Zama reservoir, which concluded that the Block 7 Consortium holds 49.6% of the gross interest in the Zama Field and PEMEX holds 50.4%. On July 2, 2021, we were notified by SENER that it had designated PEMEX as the operator of the Zama unit. During the third quarter of 2021, we submitted Notices of Dispute ("Notices of Dispute") to the Government of Mexico over decisions taken by SENER, including the designation of PEMEX as the operator of a yet-to-be unitized asset. On March 23, 2022, we received a final Unitization Resolution (the "UR") from SENER regarding the development of the Zama Field. The UR defines the rights and responsibilities of PEMEX and the Block 7 Consortium (together, the "Zama Field Participants") with respect to the development of the Zama Field. On May 26, 2022, the Zama Field Participants ratified the creation of a Unit Operating Committee ("UOC"), with participation of each party, to oversee the development of the Zama Field. Since then, we have actively engaged with PEMEX and the rest of the Block 7 Consortium to advance development. We hold a 17.35% interest in the unitized Zama Field, and we are working with the rest of the Zama Field Participants towards the finalization of the Zama Field Development Plan for submission to the CNH for final approval.

The PSC forms the basis for the Company's exploration, development and production operations on Block 7. The Block 7 PSC includes a cost recovery feature pursuant to which eligible costs in relation to the minimum work program activities are recoverable in-kind at a rate of 125% of costs from future production volumes. Production volumes are allocated in-kind between the Block 7 Consortium and the United Mexican States on a monthly basis based on the contractual value of the hydrocarbons as defined in the PSC. Up to 60% of the monthly contractual value of the hydrocarbons will be allocated to the Block 7 Consortium to recover eligible costs incurred in petroleum activities. Eligible costs exceeding 60% of the current month contractual value of the hydrocarbons will be recoverable in future periods. The amount of royalties will be determined for each type of hydrocarbons (oil, associated natural gas, non-associated natural gas and condensate) using an initial rate, adjusted thereafter for inflation. The remaining value of the hydrocarbons after the allocation for cost recovery and royalties is considered operating profit under the PSC.

The allocation of operating profit to the Block 7 Consortium after the allocation for cost recovery and royalties is 31%. The profit for oil and gas is determined on a monthly basis using an adjustment mechanism based on the projects rate of return ("ROR"). If the cumulative project's ROR in any one month exceeds 25%, the barrels of oil allocated to the Block 7 Consortium after cost recovery are reduced on a sliding scale. Once the cumulative project's internal ROR meets or exceeds 40%, the reduction locks in at a maximum rate. The Hydrocarbons Revenue Law provides that exploration and extraction activities are zero rated for value-added tax ("VAT") purposes; all other activities are taxed at 16% VAT. The 0% rates only apply to agreements between the United Mexican States and state-owned enterprises or entities, and do not apply to any other agreement executed with third parties, even in the case of exploration and extraction contracts. The Mexico income tax rate is 30%.

Carbon Capture & Sequestration

TLCS is leveraging decades of experience with conventional geology and Gulf Coast operations to pursue the development of future CCS projects. Project opportunities are actively being evaluated along the Gulf Coast. Future CCS project opportunities and the associated sequestration sites can generally be categorized into the following: (i) regional hub projects; and (ii) point source projects; which TLCS intends to identify, lease, mature and operate. Areas of development are illustrated below as of December 31, 2022:



Regional Hubs — These projects will be large, contiguous sequestration sites located proximally to large industrial emissions centers in which TLCS intends to consolidate carbon emissions from multiple contributing sources and develop large-scale CCS projects. Regional hub projects are characterized by their large size, population of diverse contributing emitters and central proximity to major emitting regions. Current regional hub projects under development are as follows:

- ***Bayou Bend CCS*** — On March 11, 2022, Bayou Bend CCS LLC ("Bayou Bend"), an equity method investment with Carbonvert, Inc. ("Carbonvert"), executed definitive lease documentation with the Texas General Land Office, formalizing the Jefferson County carbon sequestration site located in state waters offshore Jefferson County, Texas, near the Beaumont and Port Arthur, Texas industrial corridor.

On May 24, 2022, Bayou Bend executed definitive documentation with Chevron U.S.A., Inc. ("Chevron"), through its Chevron New Energies division, and closed an expanded venture to jointly develop the Bayou Bend project with Chevron. Under the terms of the transaction, Chevron acquired a 50% membership interest in Bayou Bend for gross consideration of \$50.0 million, consisting of \$30.0 million of cash at closing and up to \$20.0 million of gross contributions to Bayou Bend. This cash is expected to cover TLCS and Carbonvert's share of capital expenditures through the project's final investment decision. TLCS, Carbonvert and Chevron hold a 25%, 25% and 50% membership interest in Bayou Bend, respectively, and TLCS remains the project's operator. The three companies have also established an area of mutual interest over the full acreage in the Jefferson County offshore region contemplated in the State of Texas's original request for proposal, aligning the parties for future expansion opportunities.

For additional information on Bayou Bend, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Related Party Transactions*.

- ***River Bend CCS —*** In February 2022, an agreement was reached to lease acreage along the Mississippi River industrial corridor for a future CCS project. The lease agreement will allow for three sequestration sites near existing pipeline infrastructure that may be used for the project. TLCS will manage the project and be operator of the injection, storage, and monitoring services. TLCS will be supported by its partner, Storegga Geotechnologies Limited ("Storegga").

Point Sources — These projects will be bespoke, customized sequestration projects for individual industrial partners to capture and eliminate carbon emissions from singular sources, such as liquefied natural gas ("LNG") facilities, manufacturing plants, or power generation facilities, among others. Point source projects are characterized by their smaller footprint, individual emissions source (i.e*.,* one (1) plant) and pore space leases located nearby or on-site to that emissions source. Point source projects may carry a wider range of commercial structures than regional hubs due to their customized and directly negotiated nature, and TLCS believes the total number of point source opportunities along the Gulf Coast is significant. Current point source projects under development are as follows:

- ***Coastal Bend CCS —*** Pursuant to an option agreement with the Port of Corpus Christi Authority ("PCCA") executed in February 2022, TLCS and Howard Energy Partners ("HEP") are pursuing commercial CCS opportunities on-site at the Port of Corpus Christi. As of December 31, 2022, definitive documentation with HEP remained subject to negotiation of final terms.

- ***Freeport LNG CCS —*** In November 2021, a letter of intent with an affiliate of Freeport LNG Development, L.P. ("Freeport LNG") was executed to develop a CCS point source project immediately adjacent to its existing LNG pre-treatment facilities in Freeport, Texas. The project intends to utilize a Freeport LNG-owned geological sequestration site located less than half a mile from point of capture. This point source project benefits from a dedicated source of CO_2 and a secured injection site in close physical proximity. As of December 31, 2022, definitive documentation with Freeport LNG remained subject to negotiation of final terms.

Summary of Reserves

The following table summarizes our estimated proved reserves which are all located in the United States:

	Oil (MBbls)	Natural Gas (MMcf)	NGL (MBbls)	MBoe	Standardized Measure (in thousands)	PV -10 (in thousands)
December 31, 2022						
Proved developed producing	63,049	103,245	6,194	86,451		$ 3,935,208
Proved developed non-producing	17,236	58,482	3,121	30,104		661,882
Total proved developed	80,285	161,727	9,315	116,555		4,597,090
Proved undeveloped	10,774	57,824	3,613	24,024		584,009
Total proved	91,059	219,551	12,928	140,579	$ 4,368,448	$ 5,181,099
December 31, 2021						
Proved developed producing	70,183	108,238	7,426	95,649		$ 3,073,168
Proved developed non-producing	23,237	78,204	4,366	40,637		599,010
Total proved developed	93,420	186,442	11,792	136,286		3,672,178
Proved undeveloped	14,344	49,911	2,643	25,306		253,819
Total proved	107,764	236,353	14,435	161,592	$ 3,440,611	$ 3,925,997
December 31, 2020						
Proved developed producing	64,763	119,824	4,958	89,692		$ 1,556,221
Proved developed non-producing	20,244	84,230	3,146	37,428		197,924
Total proved developed	85,007	204,054	8,104	127,120		1,754,145
Proved undeveloped	24,300	53,154	2,754	35,913		244,340
Total proved	109,307	257,208	10,858	163,033	$ 1,904,934	$ 1,998,485

Reconciliation of Standardized Measure to PV-10

PV-10 is a non-GAAP financial measure and differs from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies without regard to the specific tax characteristics of such entities. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 of our proved reserves (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Standardized measure	$ 4,368,448	$ 3,440,611	$ 1,904,934
Present value of future income taxes discounted at 10%	812,651	485,386	93,551
PV-10 (Non-GAAP)	$ 5,181,099	$ 3,925,997	$ 1,998,485

Changes in Proved Developed Reserves

The following table discloses our estimated changes in proved developed reserves:

	Oil, Natural Gas and NGLs
	(MBoe)
Proved developed reserves at December 31, 2021	136,286
Changes during the year:	
Production	(21,723)
Revisions of previous estimates	1,994
Additions	881
Divestitures	(883)
Total proved developed reserves changes	(19,731)
Proved developed reserves at December 31, 2022	116,555

Our proved developed reserves at December 31, 2022 decreased by 19.7 MMBoe, or 14% primarily due to:

Revisions of Previous Estimates — Upward revisions of 2.0 MMBoe are due to an increase of 7.4 MMBoe related to the Ram Powell Field and Pompano Field located in the Mississippi Canyon core area and the West Cameron Field located in the Shelf and Gulf Coast core area due to performance and price revisions. This increase was offset with a decrease in the Tornado wells in the Phoenix Field located in the Green Canyon core area of 6.2 MMBoe primarily related to performance revisions from increased water volumes.

Additions — Additions of 0.9 MMBoe are primarily attributable to the successful drilling results in the Sawfish Field located in the Shelf and Gulf Coast core area and the Green Canyon 18 Field in the Green Canyon core area.

Divestitures — Divestitures of 0.9 MMBoe are primarily attributable to Brushy Creek Field located in the Shelf and Gulf Coast core area.

Development of Proved Undeveloped Reserves

The following table discloses our estimated proved undeveloped (“PUD”) reserve activities:

	Oil, Natural Gas and NGLs	Future Development Costs
	(MBoe)	(in thousands)
Proved undeveloped reserves at December 31, 2021	25,305	$ 308,032
Changes during the year:		
Extensions and discoveries	10,269	307,854
Revisions of previous estimates	(11,004)	(133,135)
Divestitures	(546)	(4,240)
Total proved undeveloped reserves changes	(1,281)	170,479
Proved undeveloped reserves at December 31, 2022	24,024	$ 478,511

Our PUD reserves at December 31, 2022 decreased by 1.3 MMBoe, or 5% primarily due to:

Extensions and Discoveries — Extensions and discoveries of 10.3 MMBoe are primarily attributable to the Ram Powell Field and Pompano Field located in the Mississippi Canyon core area. The increase includes 6.3 MMBoe associated with the successful drilling results in our Lime Rock and Venice prospects, which are awaiting completion and hookup to facilities at the Ram Powell Platform.

Revisions of Previous Estimates — Downward revisions of 11.0 MMBoe, of which 9.9 MMBoe and associated future development costs were due to the write off of a certain Phoenix Field PUD location. Annually better prospects become available to drill and as such resulted in this field location to move beyond the five year expiration.

Divestitures — Divestitures of 0.5 MMBoe are attributable to our Brushy Creek Field located in the Shelf and Gulf Coast core area.

We annually review all PUD reserves to ensure an appropriate plan for development exists. Our PUD reserves are required to be converted to proved developed reserves within five years of the date they are first booked as PUD reserves, unless the reserves are associated with an existing producing zone. Future development costs associated with our PUD reserves at December 31, 2022 totaled approximately $478.5 million, of which $388.2 million and $90.3 million is attributable to our Mississippi Canyon and Shelf and Gulf Coast core areas, respectively. When considering capital expenditures associated with other exploration projects and abandonment obligations, we expect to fund the development of PUD reserves using cash flows from operations and, if needed, availability under the Company's senior reserve-based revolving credit facility (the "Bank Credit Facility"), in each future annual period prior to the five year expiration. Our 2023 drilling program includes development of PUD reserves, and the conversion rate may not be uniform due to obligatory wells, newly acquired PUD reserves and production performance targets.

Internal Controls over Reserve Estimates and Reserve Estimation Procedures

At December 31, 2022, 2021 and 2020, proved oil, natural gas and NGL reserves attributable to our net interests in oil and natural gas properties were estimated and compiled for reporting purposes by our reservoir engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists, as described in further detail below.

Our policies regarding internal controls over the determination of reserves estimates require reserves quantities, reserves categorization, future producing rates, future net revenue and the present value of such future net revenue prepared using the definitions set forth in Regulation S-X, Rule 4-10(a) and subsequent SEC staff interpretations and guidance. These internal controls, which are intended to ensure reliability of our reserves estimations, include, but are not limited to, the following:

- reserve information, as well as models used to estimate such reserves, is stored on secure database applications to which only authorized personnel are given access rights consistent with their assigned job function;
- a comparison of historical expenses is made to the lease operating costs in the reserve database;
- internal reserves estimates are reviewed by well and by area by our reservoir engineers. A variance analysis by well to the previous year-end reserve report is performed;
- reserve estimates are reviewed and approved by certain members of senior management, including our President and Chief Executive Officer;
- our management requires that the independent petroleum engineers and geologists and our reserve quantities and calculation of the net present value of the reserves, collectively, vary by no more than 10% in the aggregate, in accordance with Society of Petroleum Evaluation Engineers ("SPEE") auditing standards;
- data is transferred to NSAI through a secure file transfer protocol site; and
- material reserve variances are discussed among NSAI, as applicable, our internal reservoir engineers and our Director of Reserves to ensure the best estimate of remaining reserves.

Because these estimates depend on many assumptions, any or all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil, natural gas and NGLs that are ultimately recovered.

During the reserves audit, NSAI did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil, natural gas and NGL production, well test data, historical costs of operation and development, product prices or any agreements relating to current and future operations of the fields and sales of production. However, if in the course of the examination something came to the attention of NSAI that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data. When compared on a well by well basis, some of our estimates are greater and some are less than the estimates of NSAI. Given the inherent uncertainties and judgments that go into estimating proved reserves, differences between internal and external estimates are to be expected. NSAI determined that its estimates of reserves have been prepared in accordance with the definitions and regulations of the SEC, including the criteria of "reasonable certainty," as it pertains to expectations about the recoverability of reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of Regulation S-X. NSAI issued unqualified audit opinions on our reserves as of December 31, 2022, 2021 and 2020 based upon its evaluations. NSAI concluded that our estimates of reserves were, in the aggregate, reasonable and have been prepared in accordance with Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPEE. The 2022 NSAI report is filed as Exhibit 99.1 to this Annual Report.

Technologies Used in Reserve Estimation

The SEC's reserves rules allow the use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil, natural gas and/or NGLs actually recovered will equal or exceed the estimate. To achieve reasonable certainty, our internal reservoir engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. The accuracy of the estimates of our reserves is a function of:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future operating costs, development costs and workovers, all of which may vary considerably from actual results;
- future prices of oil, natural gas and NGLs, which may vary considerably from those mandated by the SEC; and
- the judgment of the persons preparing the estimates.

Qualifications of Primary Internal Engineer

Our Director of Reserves is the technical person primarily responsible for overseeing the preparation of our internal reserve estimates and for coordinating reserve audits conducted by NSAI. He has over 48 years of industry experience with positions of increasing responsibility, including 40 years as a reserves evaluator or manager. His further professional qualifications include a State of Texas Professional Engineering License, extensive internal and external reserve training and asset evaluation. In addition, he is an active participant in industry reserve seminars and professional industry groups, and has been a member of the Society of Petroleum Engineers for over 48 years. He reports directly to our Vice President of Corporate Development.

Drilling Activity

The following table sets forth our drilling activity:

	Exploratory and Appraisal Wells						Development Wells						Total	
	Productive[(1)]		Dry[(2)]		Total		Productive[(1)]		Dry[(2)]		Total		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
December 31, 2022														
United States	—	—	1.0	1.0	1.0	1.0	6.0	2.8	—	—	6.0	2.8	7.0	3.8
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	1.0	1.0	1.0	1.0	6.0	2.8	—	—	6.0	2.8	7.0	3.8
December 31, 2021														
United States	—	—	2.0	1.5	2.0	1.5	5.0	2.4	—	—	5.0	2.4	7.0	3.9
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	—	—	2.0	1.5	2.0	1.5	5.0	2.4	—	—	5.0	2.4	7.0	3.9
December 31, 2020														
United States[(3)]	2.0	0.7	—	—	2.0	0.7	3.0	1.9	—	—	3.0	1.9	5.0	2.6
Mexico	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	2.0	0.7	—	—	2.0	0.7	3.0	1.9	—	—	3.0	1.9	5.0	2.6

(1) A productive well is an exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas producing well. Productive wells are included in the table in the year they were determined to be productive, as opposed to the year the well was drilled.

(2) A dry well is an exploratory or development well that is not a productive well. Dry wells are included in the table in the year they were determined not to be productive, as opposed to the year the well was drilled.

(3) One gross and net development well had a dual completion in an exploratory zone.

As of December 31, 2022, we had wells actively drilling or completing and wells suspended or awaiting completion, as follows:

	Actively Drilling or Completing				Wells Suspended or Waiting on Completion			
	Exploratory		Development		Exploratory		Development	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States	3.0	0.9	2.0	1.2	2.0	0.9	—	—
Mexico	—	—	—	—	4.0	0.7	—	—
Total	3.0	0.9	2.0	1.2	6.0	1.6	—	—

Productive Wells

The number of our productive wells is as follows for the year ended December 31, 2022:

	Gross	Net
Crude oil	203.0	151.1
Natural gas	67.0	31.9
Total[(1)]	270.0	183.0

(1) Includes 9.0 gross and 6.8 net wells with dual completions.

Acreage

Gross and net developed and undeveloped acreage is as follows for the year ended December 31, 2022:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
United States:						
Deepwater	286,671	140,051	501,244	214,771	787,915	354,822
Shelf	234,250	148,210	103,827	80,838	338,077	229,048
Total United States	520,921	288,261	605,071	295,609	1,125,992	583,870
Mexico	—	—	4,584	1,604	4,584	1,604
Total	520,921	288,261	609,655	297,213	1,130,576	585,474

Undeveloped acreage is considered to be leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether or not such acreage contains proved reserves. Included within undeveloped acreage are leased acres (held by production under the terms of a lease) that are not within the spacing unit containing, or acreage assigned to, the productive well holding such lease. The terms of our leases on undeveloped acreage as of December 31, 2022 are scheduled to expire as shown in the table below (the terms of which may be extended by drilling and production operations):

	Gross	Net
2023	186,342	106,268
2024	101,720	34,830
2025	46,166	25,778
2026	23,041	10,657
2027	86,401	38,326
2028 and beyond	165,985	81,354
Total	609,655	297,213

Crude Oil, Natural Gas and NGL Production, Prices and Production Costs

Our production volumes, average sales prices and average production costs are as follows:

	Year Ended December 31,		
	2022	2021	2020
Production Volumes:			
Crude oil (MBbls)	14,561	16,159	13,665
Natural gas (MMcf)	32,215	32,795	28,652
NGLs (MBbls)	1,793	1,875	1,559
Total (MBoe)	21,723	23,500	19,999
Percent of MBoe from crude oil	67%	69%	68%
Average Sales Price (including commodity derivatives):			
Crude oil (per Bbl)	$ 68.40	$ 49.67	$ 47.36
Natural gas (per Mcf)	$ 5.30	$ 3.11	$ 2.00
NGLs (per Bbl)	$ 33.20	$ 26.54	$ 9.90
Average (per Boe)	$ 56.46	$ 40.61	$ 35.99
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 93.75	$ 65.86	$ 37.09
Natural gas (per Mcf)	$ 7.06	$ 3.98	$ 1.87
NGLs (per Bbl)	$ 33.20	$ 26.54	$ 9.90
Average (per Boe)	$ 76.05	$ 52.96	$ 28.80
Average Lease Operating Expense (per Boe)	$ 14.18	$ 12.07	$ 12.33

Crude Oil, Natural Gas and NGL Production, Prices and Production Costs—Significant Fields

Mississippi Canyon Core Area — Pompano Field

The following table sets forth certain information regarding our production volumes, average sales prices and average production costs for the Pompano Field, which consisted of 15% or more of our 2022 total estimated proved reserves on December 31, 2022:

	Year Ended December 31,		
	2022	2021	2020
Production Volumes:			
Crude oil (MBbls)	2,809	2,716	2,852
Natural gas (MMcf)	4,759	2,626	2,179
NGLs (MBbls)	393	254	216
Total (MBoe)	3,995	3,408	3,431
Percent of MBoe from crude oil	70%	80%	83%
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 95.21	$ 67.33	$ 38.51
Natural gas (per Mcf)	$ 8.02	$ 4.68	$ 2.28
NGLs (per Bbl)	$ 31.87	$ 25.54	$ 6.51
Average (per Boe)	$ 79.63	$ 59.17	$ 33.86
Average Lease Operating Expense (per Boe)	$ 2.26	$ 3.57	$ 2.90

Expenditures and Costs Incurred

For information on property development, exploration and acquisition costs, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 14 — *Supplemental Oil and Gas Disclosures (Unaudited)*.

Title to Properties

We believe that we have satisfactory title to our oil and natural gas properties in accordance with generally accepted industry standards. Individual properties may be subject to burdens such as royalties, overriding royalties, and carried, net profits, working and other outstanding interests customary in the industry. In addition, interests may be subject to obligations or duties under applicable laws or burdens such as production payments, ordinary course liens incidental to operating agreements and for current taxes and development obligations under oil and natural gas leases. As is customary in the industry in the case of undeveloped properties, often limited investigation of record title is made at the time of acquisition. Title search investigations are made prior to the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. To the extent title opinions or other investigations reflect defects affecting such undeveloped properties, we are typically responsible for curing any such title defects at our expense.

Commodity Price Risks and Price Risk Management Activities

Production from our properties is marketed using methods that are consistent with industry practices. Sales prices for oil and natural gas production are negotiated based on factors normally considered in the industry, such as an index or spot price, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand conditions. We enter into derivative contracts on our oil and natural gas production primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. For additional information regarding our commodity price risk and commodity derivative instruments, see Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Significant Customers

Oil and natural gas companies spend capital on exploration, drilling and production operations expenditures, the amount of which is generally dependent on the prevailing view of future oil and natural gas prices which are subject to many external factors which may contribute to significant volatility in future prices. We market substantially all of our oil, natural gas and NGL production from the properties we operate and those we do not operate. Our customers consist primarily of major oil and gas companies, well-established oil and pipeline companies and independent oil and natural gas producers and suppliers. We perform ongoing credit evaluations of our customers and provide allowances for probable credit losses when necessary. For the year ended December 31, 2022, 44%, 23% and 11% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company, Valero Energy Corporation and Chevron Products Company, respectively, which are the customers that individually represented 10% or more of our oil, natural gas and NGL revenues.

Competitive Conditions

The oil and natural gas business is highly competitive in the exploration for and acquisition of reserves, the acquisition of oil and natural gas leases, equipment and personnel required to find and produce reserves and in the gathering and marketing of oil, natural gas and NGLs. We compete with large integrated oil and natural gas companies as well as independent exploration and production companies. Certain of our competitors may have significantly more financial or other resources available to them. In addition, certain of the larger integrated companies may be better able to respond to industry changes, including price fluctuation, oil and natural gas demand and governmental regulations.

However, we believe our high quality oil-weighted production base, proven expertise in utilizing seismic technology to identify, evaluate and develop exploitation and exploration opportunities, balanced mix of assets in the U.S. Gulf of Mexico deep and shallow waters and significant operating control give us a strong competitive position relative to many of our competitors.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis. Generally, but not always, the demand for gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers may impact general seasonal changes in demand.

Insurance Matters

Our oil and natural gas operations are subject to risks incident to the operation of oil and gas wells, including, but not limited to, uncontrolled flows of oil, gas, brine or well fluids into the environment, blowouts, cratering, mechanical difficulties, fires, explosions or other physical damage, pollution or other risks, any of which could result in substantial losses to us. In addition, our oil and natural gas properties are located in the U.S. Gulf of Mexico, which makes us more vulnerable to tropical storms and hurricanes. These hazards can cause personal injury or loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and the suspension of operations. Damages arising from such occurrences may result in lawsuits asserting large claims. Insurance may not be sufficient or effective under all circumstances or against all hazards to which we may be subject. A successful claim for which we are not fully insured could have a material adverse effect on our financial condition, results of operations and cash flow. Although we obtain insurance against some of these risks, we cannot insure against all possible losses. As a result, any damage or loss not covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flow.

We have insurance policies to cover some of our risk of loss associated with our operations, and we maintain the amount of insurance we believe is prudent. However, not all of our business activities can be insured at the levels we desire because of either limited market availability or unfavorable economics (limited coverage for the underlying cost).

Our general property damage insurance provides varying ranges of coverage based upon several factors, including well counts and the cost of replacement facilities. Our general liability insurance program provides a limit of $500.0 million for each occurrence and in the aggregate, and includes varying deductibles. Our Offshore Pollution Act insurance is subject to a maximum of up to $150.0 million for each occurrence and in the aggregate, including a $100,000 retention. Coverage is provided for damage to our assets resulting from a named U.S. Gulf of Mexico windstorm; however, such coverage is subject to a maximum of $200.0 million per named windstorm and in the aggregate, and is also subject to a maximum of $15.0 million per occurrence retention dependent on location. We separately maintain an operators extra expense policy with additional coverage for an amount up to $500.0 million for U.S. Gulf of Mexico Deepwater drilling wells, $150.0 million for U.S. Gulf of Mexico Shelf drilling wells, $75.0 million for U.S. Gulf of Mexico producing and shut-in wells, $75.0 million for drilling and workover in inland waters and $25.0 million for drilling and workover in onshore fields that would cover costs involved in making a well safe after a blow-out or getting the well under control; re-drilling a well to the depth reached prior to the well being out of control or blown out; costs for plugging and abandoning the well; and costs for clean-up and containment and for damages caused by contamination and pollution. For our Mexico insurance policies, we maintain $250.0 million in operators extra expense coverage for operations and $500.0 million per occurrence and aggregate limit for general liability.

We may increase or decrease insurance coverage around our key strategic assets, including potentially purchasing catastrophic bond instruments. Our highest value assets, which are located in the Phoenix Field, produce through the HP-I floating production system, which has the capability to disconnect and move away in the event of a storm, mitigating the risk of property damage.

We customarily have reciprocal agreements with our customers and vendors in which each contracting party is responsible for its respective personnel for liability related to work performed for us. Under these agreements, we generally are indemnified against third party claims related to the injury or death of our customers' or vendors' personnel, subject to the application of various states' laws.

Government Regulation

Exploration and development and the production and sale of oil, natural gas and NGLs are subject to extensive federal, state, local and foreign laws and regulations. An overview of these legal requirements is set forth below. Historically, our compliance with existing requirements has not had a material adverse effect on our financial position, results of operations or cash flows. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Because such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production.

General Overview — Our oil and natural gas operations are subject to various federal, state, local and foreign laws and regulations. Generally speaking, these regulations relate to matters that include, but are not limited to:

- location of wells;
- size of drilling and spacing units or proration units;
- number of wells that may be drilled in a unit;
- unitization or pooling of oil and natural gas properties;
- drilling and casing of wells;
- issuance of permits in connection with exploration, drilling and production;
- well production;
- spill prevention plans;
- protection of private and public surface and ground water supplies;
- emissions permitting or limitations;

- protection of endangered species;
- use, transportation, storage and disposal of fluids and materials incidental to oil and natural gas operations;
- surface usage and the restoration of properties upon which wells have been drilled;
- calculation and disbursement of royalty payments and production taxes;
- requirements for the posting of supplemental bonds or providing other forms of financial assurance for the plugging and abandonment of wells located in the U.S. Gulf of Mexico and offshore Mexico and, following cessation of operations, the removal or appropriate abandonment of all production facilities, structures and pipelines in those areas ("P&A" or "decommissioning" obligations);
- performance of P&A obligations; and
- transportation of production.

Outer Continental Shelf ("OCS") Regulation — Our operations on federal oil and natural gas leases in the U.S. Gulf of Mexico are subject to regulation by the BSEE, the BOEM and the Office of Natural Resources Revenue ("ONRR"), which are all agencies of the U.S. Department of the Interior ("DOI"). These leases are awarded by the BOEM based on competitive bidding and contain relatively standardized terms and require compliance with detailed BSEE and BOEM regulations and orders issued pursuant to various federal laws, including the federal Outer Continental Shelf Lands Acts ("OCSLA"). For offshore operations, lessees must obtain BOEM approval for exploration, development and production plans prior to the commencement of their operations. In addition to permits required from other agencies such as the U.S. Environmental Protection Agency ("EPA"), lessees must obtain a permit from BSEE prior to the commencement of drilling and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, P&A of wells on the OCS, calculation of royalty payments and the valuation of production for this purpose, and decommissioning of facilities, structures and pipelines.

President Biden issued an executive order in January 2021 suspending federal offshore and onshore oil and gas leasing pending review and reconsideration of federal oil and gas leasing and permitting practices. The suspension of these federal leasing activities prompted legal action by several states against the Biden Administration, resulting in issuance of a nationwide preliminary injunction by a federal district judge in Louisiana in June 2021 and a permanent injunction in August 2022, effectively halting implementation of the leasing suspension with respect to those leases canceled or postponed prior to March 24, 2021. The federal government and a coalition of environmental groups are appealing the district court decision but, in the interim, BOEM scheduled a lease sale for certain blocks in the U.S. Gulf of Mexico consistent with the preliminary injunction, which sale occurred in November 2021. However, on January 27, 2022, a D.C. District Court judge vacated the lease sale on the basis that BOEM failed to consider the impact on foreign greenhouse gas emissions if the November 2021 lease sale was not held and the court determined that this failure was a violation of the National Environmental Policy Act. However, in September 2022, BOEM announced that it was reinstating the lease results in line with congressional direction in the Inflation Reduction Act of 2022 (the "IRA 2022"). Separately, the DOI released its report on federal oil and gas leasing and permitting practices in November 2021, following a review of the onshore and offshore federal oil and gas program. The report states an intent to modernize the federal oil and gas leasing program and, in respect of the offshore sector, recommends strengthening financial assurance coverage amounts that are more protective of the Federal Government and taxpayers and establishing a "fitness to operate" criteria that companies would need to meet in respect of safety, environmental and financial responsibilities in order to operate on the OCS. The IRA 2022 responded to one of the report's recommendations and increased onshore royalty rates to 16.7% and offshore royalty rates to no less than 16.7% but not more than 18.8% for the next ten years, thereby ensuring the full value of the leased tracts are captured. Several of the report's other recommendations, however, require further action by the Congress and cannot be implemented unilaterally by the Biden Administration and, thus, the extent to which the Biden Administration will act upon the report's recommendations cannot be predicted at this time.

Laws and regulations are subject to change, and the trend in the United States over the past decade has been for these governmental agencies to continue to evaluate and as necessary develop and implement new, more restrictive safety, permitting and performance requirements, although under the Trump Administration there were actions seeking to mitigate certain of those more rigorous standards. For example, in 2016, the BSEE under the Obama Administration published a final rule on well control that, among other things, imposed rigorous standards relating to the design, operation and maintenance of blow-out preventers, real-time monitoring of Deepwater, high temperature, high pressure drilling activities, and enhanced reporting requirements. However, BSEE under the Trump Administration subsequently reconsidered the 2016 final rule and published final revisions to this rule that became effective in 2019 and, among other things, eliminated the requirement for a BSEE-approved verification organization for third parties providing certifications of certain critical well control functions. In another example, BSEE under the Obama Administration published a final rule in 2016 updating certain safety and pollution prevention equipment (e.g., subsea safety equipment, including blowout preventers) requirements for production safety equipment, including an obligation for independent third-party review and certification that safety and pollution prevention equipment is operational and functioning as designed in the most extreme conditions, but in 2018, BSEE amended this rule, rolling back a number of safety requirements including the third-party review and certification obligation.

BSEE and/or BOEM under the Biden Administration may reconsider regulatory actions taken by the Trump Administration, with those agencies potentially seeking to adopt additional, more stringent safety, permitting and performance requirements. For example, in the federal government's most recent list of potential regulatory actions for 2023, the DOI lists proposed rulemaking initiatives in respect to such matters as increased safety, environmental and equipment reliability protections under the pipeline and pipeline rights-of-way requirements for operating on the OCS and establishing a comprehensive program for identifying, prioritizing and managing risks associated with OCS lease and grant obligations. The DOI also lists forthcoming final rules in respect to such matters as revising certain blowout preventor systems and well control requirements for operating on the OCS. Compliance with Biden Administration legislative, executive and regulatory actions or any other legal initiatives that impact oil and natural gas exploration, development and production activities on the OCS could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. Our failure to comply with legal requirements under the OCSLA, our lease or applicable regulations may ultimately result in BOEM canceling one or more of our leases, which such cancellation could adversely affect our financial condition and operations.

Furthermore, tropical storms and hurricanes in the U.S. Gulf of Mexico can have a significant impact on oil and natural gas operations. The effects from past hurricanes have included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs. The BOEM and BSEE continue to be concerned about the loss of these facilities and rigs as well as the potential for catastrophic damage to key infrastructure and the resultant pollution from future storms. In an effort to reduce the potential for future damage, the BOEM and the BSEE have periodically issued guidance aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures. It is possible that similar, if not more stringent, requirements will be issued by the BOEM and the BSEE for future hurricane seasons. New requirements, if any, could increase our operating costs and/or capital expenditures.

In addition, in order to cover the various decommissioning obligations of lessees on the OCS, the BOEM generally requires that lessees post some form of acceptable financial assurances that such obligations will be met, such as surety bonds. The cost of such bonds or other financial assurance can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations and provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In 2016, the BOEM under the Obama Administration issued Notice to Lessees and Operators ("NTL") #2016-N01 ("2016 NTL") to clarify the procedures and guidelines that BOEM Regional Directors use to determine if and when additional financial assurances may be required for OCS leases, rights of way ("ROWs") and rights of use and easement ("RUEs"). However, the 2016 NTL was not fully implemented as the BOEM under the Trump Administration rescinded the NTL in 2020 and, in October 2020, pursued a proposed rule published jointly with the BSEE that sought to clarify and provide greater transparency to decommissioning and related financial assurance requirements imposed on oil and gas lessees (record title owners), sublessees (operating rights owners) and RUE and ROW grant holders conducting operations on the federal OCS. Although the notice of proposed rulemaking has not been formally withdrawn, consistent with recommendations made in the November 2021 DOI leasing report in response to President Biden's January 2021 executive order, it is anticipated that the Biden Administration could pursue more stringent financial assurance requirements that could increase our operating costs. Additionally, in August 2021, the BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder in respect of any new, more stringent, NTLs or final rules on supplemental bonding published by the BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the interest holder's decommissioning liabilities.

Regulation in Shallow Waters Off the Coast of Mexico — Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by SENER, the CNH and other Mexican regulatory bodies. The CNH is responsible for, among other things, overseeing the tender procedures for awarding contracts for the exploration and production of oil and natural gas in Mexican waters, managing and supervising contracts that have been awarded, and approving exploration and production plans. The PSC that the Block 7 Consortium entered into for the development of this acreage contains terms that impose on us the duty to comply with various laws and regulations. These laws and regulations govern, among other things, the exploration and exploitation of hydrocarbons (including certain national content requirements), the treatment, conveyance, marketing, transport and storage of petroleum, and requirements for industrial safety, operational security, and facility decommissioning. Failure to comply can result in the imposition of monetary penalties, revocation of permits, rescission of the PSC, suspension of operations, and ordered decommissioning of offshore facilities and systems. The laws and regulations governing activities in the Mexican energy sector were significantly reformed in 2013, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore shallow waters.

Hydrocarbon Export Regulation in Mexico — Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by SENER. Such regulations are subject to change, and it is possible that the Mexican National Agency of Industrial Safety and Environmental Protection of the Hydrocarbons Sector ("ASEA") or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. For example, in December 2020, SENER published regulations affecting the granting of permits for the import and export of hydrocarbons. These regulations imposed additional constraints on permit applicants, and granted SENER more discretion in issuing, modifying, and revoking those permits. Previously, such permits would have had a term of 20 years – the December 2020 regulations limit terms to 5 years, restrict extensions and add new requirements. Subsequently, in May 2021, the Mexican government amended its federal Hydrocarbons Law in a manner that is anticipated to be beneficial to PEMEX, but have an adverse impact on privately-held oil and gas energy companies including by way of example, (i) authorizing SENER and the Mexican Energy Regulatory Commission (the "CRE") to suspend or revoke hydrocarbon permits if there is imminent danger to national security, energy security or the national economy; (ii) allowing the government to temporarily occupy the facilities of hydrocarbon permit-holders to safeguard the national interest and hand over the operation of such facilities to State-owned entities, such as PEMEX; and (iii) allowing for denial by default of applications for new permits of private companies if the authorities do not respond within 90 days. Also in May 2021, the Mexican government made a second amendment to its Hydrocarbons Law, which such amendment halts the CRE's power to enforce asymmetric regulation in the hydrocarbon, petroleum products and petrochemical markets, which regulation obligates PEMEX to comply with certain obligations that effectively limits its market position relative to its competitors. Amparo actions are being pursued in local courts in response to these legal changes and, as interim measures, court actions suspended the December 2020 regulations in March 2021, partially suspended portions of the first amendment to the Hydrocarbons Law (such suspension including the authorization to temporarily occupy facilities of permit-holders) in May 2021 and suspended the second amendment to the Hydrocarbons Law in May 2021. The suspension is to be appealed by SENER.

Environmental and Occupational Safety and Health Regulations

We are subject to various federal, state, local and foreign regulations concerning occupational safety and health as well as the discharge of materials into, and the protection of, the environment. Environmental laws and regulations relate to, among other things:

- assessing the environmental impact of seismic acquisition, drilling or construction activities;
- the generation, storage, transportation and disposal of waste materials;
- the emission of certain gases into the atmosphere;
- the monitoring, abandonment, reclamation and remediation of well and other sites, including sites of former operations;
- various environmental permitting requirements, such as permits for wastewater discharges;
- the development of emergency response and spill contingency plans;
- specific operating criteria addressing worker protection; and
- protection of private and public surface and ground water supplies.

Based on regulatory trends and increasingly stringent laws, our capital expenditures and operating expenses related to the protection of the environment and safety and health compliance have increased over the years and it is possible such expenses will continue to increase in the future. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters, and the cost of compliance could be significant. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, natural resource damages or the issuance of injunctive relief (including orders to cease operations). Both onshore and offshore drilling in certain areas has been opposed by environmental groups and, in certain areas, has been restricted. Additionally, President Biden has made the combat of climate change arising from GHG emissions a priority under his administration. Some environmental laws and regulations may impose strict liability, which could subject us to liability for conduct that was lawful at the time it occurred or conduct or conditions caused by prior operators or third parties. To the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore or offshore drilling or imposes environmental protection requirements that result in increased costs to the oil and gas industry in general, our business and financial results could be adversely affected.

We expect to continue making expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. Our insurance coverage provides for the reimbursement to us of certain costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure against pollution and similar environmental risks. We do not anticipate that we will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent under the Biden Administration including in respect of GHG emissions, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Water Discharges — Our discharges into waters of the United States are limited by the federal Clean Water Act, as amended ("CWA"), and analogous state laws. The CWA prohibits any discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States, except in compliance with permits issued by federal and state governmental agencies. These discharge permits also include monitoring and reporting obligations. Failure to comply with the CWA, including discharge limits set by permits issued pursuant to the CWA, may also result in administrative, civil or criminal enforcement actions. Violations of the CWA can result in suspension, debarment or the imposition of statutory disability, each of which prevents companies and individuals from participating in government contracts and receiving some non-procurement government benefits. The CWA also requires the preparation of oil spill response plans and spill prevention, control and countermeasure plans.

Oil Pollution Act — The Oil Pollution Act of 1990, as amended ("OPA"), holds owners and operators of offshore oil production or handling facilities, including the lessee or permittee of the area where an offshore facility is located, strictly liable for the costs of removing oil discharged into waters of the United States and for certain damages from such spills. OPA assigns joint and several strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by OPA, they are limited. OPA's damages liability cap is currently $137.7 million; however, a party cannot take advantage of liability limits if a spill was caused by gross negligence or willful misconduct, resulted from violation of a federal safety, construction or operating regulation, or if the party failed to report a spill or cooperate fully in the clean-up. OPA also requires responsible parties to maintain evidence of financial responsibility in prescribed amounts. OPA currently requires a minimum financial responsibility demonstration of between $35 million to $150 million, based on a worst case oil spill discharge volume, for companies operating on the OCS, although the BOEM may increase this amount in certain situations, but in no event greater than $150 million. From time to time, the United States Congress has proposed, but not adopted, amendments to OPA raising the financial responsibility requirements. If OPA is amended to increase the minimum level of financial responsibility, we may experience difficulty in providing financial assurances sufficient to comply with this requirement. We cannot predict at this time whether OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if an oil discharge or substantial threat of discharge were to occur, we may be liable for costs and damages, which costs and liabilities could be material to our results of operations and financial position.

National Environmental Policy Act — The National Environmental Policy Act, as amended ("NEPA"), requires federal agencies, including the DOI, to consider the impacts their actions have on the human environment, and to prepare detailed statements for major federal actions having the potential to significantly impact the environment. These requirements can lead to additional costs and delays in permitting for operators as the DOI or its bureaus may need to prepare Environmental Assessments ("EA") and more detailed Environmental Impact Statements ("EIS") in support of its leasing and other activities that have the potential to significantly affect the quality of the environment. If the EA indicates that no significant impact is likely, then the agency can release a finding of no significant impact and carry on with the proposed action. Otherwise, the agency must then conduct a full-scale EIS. In July 2020, the Council on Environmental Quality ("CEQ") under former President Trump's Administration published a final rule modifying the NEPA including, among other things, establishing a time limit of two years for preparation of EIS statements and one year for the preparation of EAs, and also eliminating the responsibility to consider cumulative effects of a project. While the July 2020 rule modifying NEPA remains subject to ongoing litigation in several federal district courts, the CEQ, now under the Biden Administration, announced in October 2021, that it intends to make three significant changes to the 2020 final rule, including authorizing agencies to consider direct, indirect and cumulative effects of major federal actions including upstream and downstream GHG emissions impacts of fossil fuel projects, allowing agencies to determine the purpose and need of a project, which allows consideration of less-harmful alternatives, and affording agencies greater flexibility in crafting their own NEPA procedures, consistent with CEQ regulations, so as to meet the agencies' and public's needs. To that end, in April 2022, the CEQ issued a final rule in line with the proposed changes, a move considered as "Phase I" of the Biden Administration's two-phased approach to modifying the NEPA. "Phase 2" of this process includes the release of a new rule proposing the broader changes to the NEPA regulations. Additionally, in January 2023, the CEQ released guidance to assist federal agencies in assessing the GHG emissions and climate change effects of their proposed actions under NEPA. The CEQ's interim guidance is effective immediately and encourages agencies to consider, among other things, effects from upstream and downstream GHG emissions of fossil fuel projects and, in many cases, use estimates of the social costs of GHGs when communicating those findings to the public. The NEPA process involves public input through comment. These comments, as well as the agency's analysis of the proposed project, can result in changes to the nature of a proposed project, such as by limiting the scope of the project or requiring resource-specific mitigation. The adequacy of the agency's NEPA process can be challenged in federal court by process participants. This process may result in delaying the permitting and development of projects, and result in increased costs.

Endangered Species Act — The Endangered Species Act, as amended ("ESA"), restricts activities that may affect federally identified endangered and threatened species or their habitats. Additionally, the Migratory Bird Treaty Act, as amended ("MBTA"), implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds. Under the MBTA, the taking, killing or possessing of migratory birds is unlawful without a permit. The U.S. Fish and Wildlife Service ("FWS") under former President Trump issued a final rule on January 7, 2021, which notably clarifies that criminal liability under the MBTA will apply only to actions "directed at" migratory birds, its nests or its eggs; however, in October 2021, the FWS under the Biden Administration revoked the Trump Administration's rule on incidental take and published an advanced notice of proposed rulemaking to codify a general prohibition on incidental take while establishing a process to regulate or permit exceptions to such a prohibition. A notice of proposed rulemaking is scheduled for release toward the end of the first quarter of 2023. The Marine Mammal Protection Act, as amended ("MMPA"), similarly prohibits the taking of marine mammals without authorization. Additionally, the FWS may make determinations on the listing of species as threatened or endangered under the ESA and litigation with respect to the listing or non-listing of certain species may result in more fulsome protections for non-protected or lesser-protected species. We conduct operations on oil and natural gas leases in areas where certain species that are protected by the ESA, MBTA and MMPA are known to exist and where other species that could potentially be protected under these statutes are known to exist. The FWS or the National Marine Fisheries Service may designate critical habitat that it believes is necessary for survival of a threatened or endangered species. A critical habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for oil and natural gas development. These statutes may result in operating restrictions or a temporary, seasonal or permanent ban in affected areas.

***Hazardous Substances and Waste Management* —** The Resource Conservation and Recovery Act, as amended ("RCRA"), generally regulates the disposal of solid and hazardous wastes and imposes certain environmental cleanup obligations. Although RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy," the EPA and state agencies may regulate these wastes as solid wastes. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any future loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in increased costs to manage and dispose of generated wastes. Also, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

***Comprehensive Environmental Response, Compensation and Liability Act* —** The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on persons that are considered to have contributed to the release of a "hazardous substance" into the environment. Such "responsible persons" may be subject to joint and several liability under CERCLA for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Further, it is not uncommon for coastal landowners or other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Air Emissions — The Clean Air Act, as amended ("CAA"), and comparable state statutes restrict the emission of air pollutants and affect both onshore and offshore oil and natural gas operations. New facilities may be required to obtain separate construction and operating permits before construction work can begin or operations may start, and existing facilities may be required to incur capital costs in order to remain in compliance. Also, the EPA has developed, and continues to develop, more stringent regulations governing emissions of toxic air pollutants and is considering the regulation of additional air pollutants and air pollutant parameters. For example, in 2015, the EPA under the Obama Administration issued a final rule under the CAA, making the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone more stringent. Since that time, the EPA has issued area designations with respect to ground-level ozone and, more recently, in December 2020, the EPA, under the Trump Administration, published a final action that, upon conducting a periodic review of the ozone standard in accord with CAA requirements, elected to retain the 2015 ozone NAAQS without revision on a going-forward basis. However, several groups filed litigation over this December 2020 decision, and, in October 2021, the EPA announced it would reconsider the decision with a target date of year end of 2023. A draft assessment released in April 2022 indicates EPA staff have reached a preliminary conclusion that the December 2020 decision will stand, but uncertainty remains until a final decision is released. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Worker Health and Safety — The Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

***Climate Change* —**The threat of climate change continues to attract considerable public, governmental and scientific attention in the United States and in foreign countries. President Biden has made action on climate change a priority of his administration's agenda and laws such as the IRA 2022 advance numerous climate-related objectives. Additionally, numerous proposals have been made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHG as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, the EPA has adopted regulations under the existing CAA that, among other things, impose pre-construction and operating permit requirements on certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources and implement New Source Performance Standards directing the reduction of methane from certain new, modified or reconstructed facilities in the oil and natural gas sector. Compliance with these rules or others could result in increased compliance costs on our operations. In November 2021, the EPA issued a proposed rule that would make methane emissions from the crude oil and natural gas sources category more stringent, by establishing Quad Ob new source and Quad Oc first-time existing source standards of performance for methane and volatile organic compound emissions for new sources and existing sources in the crude oil and natural gas source category. The EPA published a supplemental proposal in November 2022 which, among other items, would impose expanded inspection, monitoring, and emissions controls requirements on oil and gas sites and strengthen emissions requirements related to equipment and routine flaring. The proposal is currently subject to public comment and is expected to be finalized in 2023. It is likely, however, that these regulatory actions will be subject to legal challenges, so we are unable to predict at this time the scope of any final regulatory requirements and the expected cost to comply with such requirements. Any increase in regulatory scope and oversight may increase compliance expenditure or mitigation costs for our operations.

Additionally, state implementation of revised air emission standards could result in stricter permitting requirements, delay, limit or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement among participating nations to limit their GHG emissions through individually-determined emissions reduction goals every five years after 2020. President Biden announced in April 2021 a new, more rigorous nationally determined emissions reduction level of 50-52% reduction from 2005 levels in economy-wide net GHG emissions by 2030. Moreover, the international community gathered again in Glasgow in November 2021 at the 26th Conference of the Parties ("COP26"), during which multiple announcements (not having the effect of law) were made, including a call for parties to eliminate certain fossil fuel subsidies and pursue further action on non-CO_2 GHGs. Relatedly, the United States and European Union jointly announced at COP26 the launch of a Global Methane Pledge, an initiative which over 100 countries joined, committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. In November 2022, the Government of the Arab Republic of Egypt hosted the 27th session of the Conference of the Parties ("COP27"). At COP27 in Sharm El-Sheik, countries reiterated the agreements from COP26 and were called upon to accelerate efforts toward the phase out of inefficient fossil fuel subsidies. The United States also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity gas. Although no firm commitment or timeline to phase out or phase down all fossil fuels was made at COP27, there can be no guarantees that countries will not seek to implement such a phase out in the future. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, COP27, or other international conventions cannot be predicted at this time and it is unclear what additional initiatives may be adopted or implemented that may have a negative impact on our financial condition.

Governmental, scientific and public concern over the threat of climate change arising from GHG emissions has resulted in increasing federal political risk regarding climate change. In the United States, President Biden has issued several executive orders calling for more expansive action to address climate change and limit new oil and gas operations on federal lands and waters. See Part I, Items 1 and 2. Business and Properties – Government Regulation – Outer Continental Shelf (“OCS”) Regulation for more information. Other actions that could be pursued by the Biden Administration include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of LNG export facilities, as well as more stringent emissions standards for oil and gas facilities. Additionally, the IRA 2022 was signed into law in August 2022, and contains hundreds of billions of dollars in incentives for the development of renewable energy, clean fuels, electric vehicles and supporting infrastructure, and carbon capture and sequestration, among other provisions. These incentives could further accelerate the transition of the United States’ economy away from the use of fossil fuels toward lower- or zero-carbon emissions alternatives. The IRA 2022 also imposes the first ever federal fee on the emissions of GHGs through a methane emissions charge. Litigation risks are also increasing, as a number of cities, local governments and other plaintiffs have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors or customers by failing to adequately disclose those impacts. We are not currently a defendant in any of these lawsuits but could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Additionally, our access to capital may be impacted by climate change policies. Stockholders and bondholders currently invested in fossil fuel energy companies such as ours, but concerned about the potential effects of climate change, may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices that favor “clean” power sources, such as wind and solar, making those sources more attractive, and some of them may elect not to provide funding for fossil fuel energy companies. Many of the largest U.S. banks have made “net zero” carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. At COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. Additionally, there is the possibility that financial institutions will be required to adopt policies that limit funding to fossil fuel energy companies.

In late 2020, the Federal Reserve announced that it had joined the Network for Greening the Financial System (“NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector, and, in September 2022, announced that six of the U.S.’ largest banks will participate in a pilot climate scenario analysis exercise to enhance the ability of firms and supervisors to measure and manage climate-related financial risk. The Federal Reserve released its pilot exercise in January 2023 which is designed to analyze the impact of both physical and transition risks related to climate change on specific assets of the banks’ portfolios. While we cannot predict what policies may result from these announcements, a material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and operations. Separately, the SEC released a proposed rule in March 2022 that would establish a framework for the reporting of climate risks, targets and metrics. A final rule is anticipated to be released in the second quarter of 2023. Although the final form and substance of this rule and its requirements are not yet known, and the ultimate impact on our business is uncertain, the proposed rule, if finalized, may result in increased compliance costs, increased costs of and restrictions on access to capital. The SEC has also announced that it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege that an issuer’s existing climate disclosures are misleading or deficient. These agency actions could increase the potential for litigation.

Finally, some scientists have concluded that increasing concentrations of GHG emissions in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other extreme climatic events, as well as chronic shifts in temperature and precipitation patterns. Our offshore operations are particularly at risk from severe climatic events, which have the potential to cause physical damage to our assets and thus could have an adverse effect on our exploration and production operations. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we produce. While our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Environmental Regulation in Shallow Waters Off the Coast of Mexico — Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by the ASEA. We must obtain ASEA-issued permits and comply with ASEA regulations governing hydrocarbon activities, including requirements for environmental impact and risk assessments, industrial safety, waste management, water and air emissions, operational security and facility decommissioning. Failure to comply with applicable laws and regulations can result in the imposition of monetary penalties, revocation of permits, suspension of operations and ordered decommissioning of offshore facilities and systems. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are relatively new, having been significantly reformed following the establishment of ASEA in 2014 as a result of federal constitutional amendments approved in 2013, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our environmental compliance-related operating costs and/or capital expenditures for operations in Mexican offshore shallow waters.

For example, in May 2020, the ASEA published the Industrial Safety, Operational Safety and Environmental Protection Guidelines for the Closing, Dismantling and Abandonment of Hydrocarbons Sector Facilities (the "Dismantling Guidelines"). The Dismantling Guidelines are mandatory for all hydrocarbon sector facilities that perform dismantling, abandonment and closing of hydrocarbon sector activities. The Dismantling Guidelines set out several obligations in terms of safety, reporting and risk, including establishing a closing, dismantling and/or abandonment activities program for each of the relevant phases. Additionally, during the fourth quarter of 2021, ASEA announced its implementation of a "Popular Denunciation System" that will utilize an internet-based platform to allow persons, organizations and companies to anonymously report complaints against entities and companies operating in Mexico, including in respect of safety and environmental incidents such as, for example, hydrocarbon spills and pollution events. We anticipate that ASEA will conduct investigations to substantiate the incidents identified in the new reporting system.

Under the Block 7 PSC, we are jointly and severally liable for the performance of all obligations under the PSC, including exploration, appraisal, extraction and abandonment activities and compliance with all environmental regulations, and failure to perform such obligations could result in contractual rescission of the PSC.

Federal Regulation of Sales and Transportation of Natural Gas — Our sales of natural gas are affected directly or indirectly by the availability, terms and cost of natural gas transportation. The prices and terms for access to pipeline transportation of natural gas are subject to extensive federal and state regulation. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA") and by regulations and orders promulgated under the NGA and/or NGPA by the Federal Energy Regulatory Commission ("FERC"). In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the United States Congress and by FERC regulations. However, certain offshore gathering and transportation services we rely upon are subject to limited FERC regulation and are regulated by the states.

Pursuant to authority delegated to it by the Energy Policy Act of 2005 ("EPAct 2005"), FERC promulgated anti-manipulation regulations establishing violation enforcement mechanisms that make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of FERC to (i) use or employ any device, scheme or artifice to defraud, (ii) make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading or (iii) engage in any act, practice or course of business that operates or would operate as a fraud or deceit upon any entity. The EPAct 2005 also amended the NGA and the NGPA to give FERC authority to impose civil penalties for violations of these statutes and regulations, up to $1,388,496 per violation, per day for 2021 (this amount is adjusted annually for inflation). FERC may also order disgorgement of profits and corrective action. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which includes annual reporting requirements for entities that purchase or sell a certain volume of natural gas in a given calendar year. We believe, however, that neither the EPAct 2005 nor the regulations promulgated by FERC as a result of the EPAct 2005 will affect us in a way that materially differs from the way they affect other natural gas producers, gatherers and marketers with which we compete.

Our sales of oil and natural gas are also subject to market manipulation and anti-disruptive requirements under the Commodity Exchange Act ("CEA") as amended by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), and regulations promulgated thereunder by the U.S. Commodity Futures Trading Commission (the "CFTC"). The CFTC prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

The current statutory and regulatory framework governing interstate natural gas transactions is subject to change in the future, and the nature of such changes is impossible to predict. We cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by the United States Congress, the applicable federal agencies, or the various state legislatures, and what effect, if any, the proposals might have on our operations. The natural gas industry historically has been very heavily regulated. In the past, the federal government regulated the prices at which natural gas could be sold. Since 1978, various federal laws have been enacted that have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. However, we are subject to reporting requirements imposed by FERC. There is always some risk, however, that the United States Congress may reenact price controls in the future. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines or impose additional reporting or other requirements upon our operations, and we cannot predict what future action FERC will take. Therefore, there is no assurance that the current regulatory approach recently pursued by FERC and the United States Congress will continue. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil — FERC regulates the interstate pipeline of crude oil, petroleum products and other liquids, such as NGLs. Our sales of crude oil and condensate are currently not regulated and are made at negotiated prices. There is always some risk, however, that the United States Congress may reenact crude oil, petroleum products and NGL price controls in the future. We cannot predict whether new legislation to regulate crude oil, or the prices charged for crude oil might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Additionally, such sales may be subject to certain state, and potentially federal, reporting requirements.

Our ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"), and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. Certain regulations implemented by FERC in recent years and certain pending rulemaking and other proceedings could result in an increase in the cost of transportation service on certain petroleum products pipelines. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other crude oil and condensate producers with which we compete.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to other crude oil and condensate producers with which we compete.

We have an undivided interest in a pipeline owned by CKB Petroleum, Inc. that is subject to FERC jurisdiction under the ICA, but FERC has granted us a temporary waiver of the filing and reporting requirements. This pipeline is still subject to FERC's jurisdiction under the ICA and is still subject to the other requirements of the ICA. If the facts upon which the waiver was granted change materially, we are required to inform FERC, which may result in revocation of the waiver. If conditions change such that the pipeline no longer qualifies for a waiver, we may be subject to regulation by FERC of the rates, terms and conditions of service on the CKB Petroleum, Inc. pipeline; however, these burdens generally would not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar pipelines.

FERC also implements the OCSLA pertaining to transportation and pipeline issues, which requires that all pipelines operating on or across the OCS provide nondiscriminatory transportation service. We own and operate pipelines that are located in the OCS and are subject to the non-discrimination requirements in the OCSLA.

Human Capital

Our employees are our most valuable asset and are a key factor in our success. We strive to provide a work environment that attracts and retains top talent, reflects our core values, and fosters an innovative and collaborative culture. In 2022, we finalized and established our Talos Energy Culture Roadmap with five defined pillars to shape the employee experience with purpose. The five key principles define our culture and represent a shared set of values, goals, attitudes, and practices that make up our organization – Think as an Owner, Embody Integrity & Safety, Maintain Optionality, Empower Each Other, and Embrace Diversity & Inclusion. Our human capital measures and objectives focus on several areas, including, but not limited to human rights, diversity and inclusion, assuring the safety of our employees, employee recruitment and development and offering a fulsome array of employee health and welfare benefits. We are focused on developing a diverse team of qualified employees and creating an inclusive workplace culture. While we may reference certain policies and other documents in these disclosures, these are primarily to identify the existence of such policies. They are not, and should not be deemed to be, incorporated into this Annual Report or any of our other SEC filings.

As of December 31, 2022, we employ approximately 436 people located primarily in Texas, Louisiana and Mexico, 216 of whom are employed in offshore operations. In addition, we supplement our workforce with contractors and consultants. While headcount does not significantly fluctuate throughout the year, in order to align our workforce with the pace of our business, headcount might increase or decrease in response to various factors, including acquisition activity, unscheduled shut-ins or a change in our capital program. None of our employees are represented by labor unions or covered by any collective bargaining agreement.

Safety — At Talos, safety is defined as freedom from unacceptable risk of harm and an empowered workforce promoting a safety-first culture across our operations. Safety in every aspect of our business is our number one priority and is core to our Health, Safety, Environment, and Sustainability operational culture. We drive this culture by being fully transparent in our reporting of safety and ESG matters to our Board of Directors and stakeholders on a regular basis, including our continual collaboration with the BSEE and the United States Coast Guard. The scope and oversight of the Board's Safety, Sustainability & Corporate Responsibility Committee includes ESG and corporate responsibility matters. We rigorously train our employees to conduct operations in accordance with our strict safety standards and encourage employees to immediately report any breach of safety protocol to their supervisor or our compliance hotline. Our employees are empowered and obligated by our Chief Executive Officer to exercise the Stop Work Authority ("SWA"). With SWA, our employees can call an immediate stop to any work for any safety concern without fear of retaliation or intimidation.

Conducting regular safety training allows us to proactively address the dynamic nature of offshore operational risk and promote a robust culture of offshore safety. Our employees and permanently assigned contractors complete custom designed in-house trainings through our eLearning platform and role appropriate hands-on training upon hiring and as part of a continuous development program. Employees are engaged in biweekly field safety meetings directly with senior management to discuss safety culture and ESG initiatives. Employees and contractors conduct emergency response training drills on each facility at least once per hitch allowing our employees to always be ready in case of an emergency situation. After any serious incident we conduct thorough incident investigations and communicate a lessons learned report and any changes to our safety policies to all offshore employees.

Safety performance is an element of each employee's performance review and 10% of the value of the 2022 short-term incentive award pool was based upon our achievement of safety goals. Additionally, our offshore employees are eligible to receive a quarterly safety bonus, the value of which is contingent upon the number of safety or environmental incidents of non-compliance recorded at the employee's facility location during the quarter.

Finally, many of our offshore employees participate in our ESG sub-committees so they can have a voice in corporate-level decisions about ESG matters. Our ESG efforts strive to continually improve our safety and environmental performance and our employees help determine the responsible path forward.

Human Rights — We remain committed to upholding human rights across every segment of our business. Our Code of Business Conduct and Ethics, which applies to all of our directors, officers and other employees of the Company, and our Vendor Code of Conduct work in tandem to establish our commitment to human rights as a fundamental part of our responsibilities as a company. Our policy also addresses areas of potential concern including respecting employees' rights to all types of associations without fear of discrimination, employees' right to be paid a living wage, the prohibition of forced labor, prevention of human trafficking and child labor. In 2021, we published our Talos Human Rights Policy to further strengthen our commitment to safeguard human rights.

Indigenous Rights — While our operations are predominantly offshore, we nonetheless strive to embody a commitment to respect the rights of indigenous people. We are committed to completing all operations in compliance with applicable national laws and treaties. We recognize the importance of respecting indigenous people and communities.

Diversity and Inclusion — We believe that creating a work environment where employees feel welcome, supported and valued results in increased employee engagement and reduced turnover. In order to achieve these goals, we carefully observe all applicable laws and have adopted and actively enforce policies in our Employee Handbook and Code of Business Conduct and Ethics that ensure equal employment opportunities for all and prohibit harassment and discrimination of any kind. Our Code of Business Conduct and Ethics requires adherence to the highest standards of personal integrity and assures the protection of human rights. We have a compliance hotline so that employees can report any violation of these policies anonymously if they wish. We know that a diverse workforce brings expanded creativity, stronger problem-solving skills and leads to better decision-making and enhanced performance. Our Code of Business Conduct and Ethics requires that our directors, officers and employees treat each of our employees with the same high level of respect regardless of such employee's age, color, disability, ethnicity, family or marital status, gender identity or expression, language, national origin, physical and mental ability, political affiliation, race, religion, sexual orientation, socio-economic status, veteran status or other characteristics that make such employee unique. As reflected in our Code of Business Conduct and Ethics, we are committed to working in partnership with vendors and other business partners directly linked to our operations that share our commitment to these same principles.

Recruitment, Development and Training — We foster an entrepreneurial culture where open communication is encouraged, the views of our employees are heard, and the results of their efforts are recognized. This is one of the reasons why every year since our inception, we have earned a ranking as a Top Workplace on the Houston Chronicle Top Workplaces list. We operate an inclusive and dynamic recruiting process that utilizes online recruiting platforms, referrals, internships and professional recruiters. We foster the growth and professional development of our employees through robust performance review process, which includes the creation of performance development goals and plans to achieve those goals in order to help our employees reach their full potential. In 2022, we launched the Leadership Development Program available to all employees to help build more dynamic and engaged leaders. We also offer in-house training, eLearning through our Learning Management System, reimbursement of the costs of outside training, and tuition reimbursement to support our employees' pursuit of higher education at accredited institutions in further support of developing our employees. We believe this emphasis on development and training has contributed to our low 6.6% voluntary turnover rate for 2022.

Health and Welfare Benefits — We work to retain employees by offering competitive wages and generous benefits that are designed to meet the varied and evolving needs of a diverse workforce. We provide employees with the ability to participate in health and welfare plans, including medical, dental, life, accidental death and dismemberment and short-term and long-term disability insurance plans. In addition, we offer extended comprehensive benefits that include 401(k) match, confidential support through the Employee Assistant Program, subsidy for gym memberships, paid time off and leaves of absence, as well as a Work From Home program launched at the end of 2021.

Community & Social Engagement — We are committed to supporting and giving back to the communities in which we operate and live. We recognize the link between local communities, the success of our employees, and ultimately the success of our business. To take a more proactive role in community support, our Community Committee, comprised of our employees, engages directly in outreach, fundraising, education and awareness. We regularly host volunteer and fundraising events supporting non-profit organizations in our communities, annually provide a $500 allowance to every employee that can be applied in support of a non-profit of their choice, match funds raised by the Community Committee's fundraising efforts for charitable organizations, and provide employees with a paid volunteer day off to support an organization where they want to donate their time.

Available Information

We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, all amendments to those reports, and all other information filed with or furnished to the SEC available, free of charge, through our website, https://www.talosenergy.com, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. The filings are also available by accessing the SEC's website at https://www.sec.gov.

We voluntarily publish annual sustainability reports which are available free of charge on our corporate website at: https://www.talosenergy.com/sustainability/. Information included in these sustainability reports is not incorporated into this Annual Report or in any other report or document we file with the SEC.

Item 1A. Risk Factors

Certain factors may have a material adverse effect on our business, financial condition, and results of operations. You should consider carefully the risks and uncertainties described below, in addition to other information contained in this Annual Report, including our Consolidated Financial Statements and related notes. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties that we are unaware of, or that we currently believe are not material, may also become important factors that adversely affect our business. If any of the following risks actually occur, our business, financial condition, results of operations and future prospects could be materially and adversely affected. In that event, the trading price of our common stock could decline, and you could lose part or all of your investment.

Risks Related to our Business and the Oil and Natural Gas Industry

Oil and natural gas prices are volatile. Stagnation or declines in commodity prices may adversely affect our financial condition and results of operations, cash flows, access to the capital markets and ability to grow.

Our revenues, cash flows, profitability and future rate of growth substantially depend upon the market prices of oil and natural gas. Prices affect our cash flows available for capital expenditures and our ability to access funds under our Bank Credit Facility and through the capital markets. The amount available for borrowing under our Bank Credit Facility is subject to a borrowing base, which is determined by the lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models to be determined by the lenders at such time. Further, because we use the full cost method of accounting for our oil and gas operations, we perform a ceiling test each quarter, which is impacted by declining prices. Significant price declines could cause us to take ceiling test write-downs, which would be reflected as non-cash charges against current earnings. See the Risk Factor entitled "Lower oil and natural gas prices and other factors in the future may result in ceiling test write-downs and other impairments of our asset carrying values" for further discussion.

In addition, significant or extended price declines may also adversely affect the amount of oil and natural gas that we can economically produce. A reduction in production and/or the prices we receive for our production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively impact our ability to replace our production and our future rate of growth.

The markets for oil and natural gas have been volatile historically and are likely to remain volatile in the future. For example, during the period January 1, 2020 through December 31, 2022, the daily NYMEX WTI crude oil price per Bbl ranged from a low of $(36.98) to a high of $123.64, and the daily NYMEX Henry Hub natural gas price per MMBtu ranged from a low of $1.33 to a high of $23.86. Subsequent to December 31, 2022, NYMEX WTI crude oil and NYMEX Henry Hub natural gas prices recorded daily lows of $72.82 per Bbl and $2.17 per MMBtu, respectively.

The prices we receive for our oil and natural gas depend upon many factors beyond our control, including, among others:

- changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- level of consumer product demands;
- hurricanes and other adverse climatic conditions;
- the impact of applicable market differentials, including those relating to quality, transportation, fees, energy content and regional pricing;
- domestic and foreign governmental actions, regulations and taxes;
- price and availability of alternative fuels;
- political and economic conditions in oil-producing countries, particularly those in the Middle East, Russia, South America and Africa;
- Russia's ongoing war in Ukraine and resulting sanctions in response thereto;

- the occurrence or threat of epidemic or pandemic diseases, such as the outbreak of COVID-19, or any government response to such occurrence or threat;
- actions by OPEC Plus relating to oil and natural gas price and production controls;
- U.S. and foreign supply of oil and natural gas;
- price and quantity of oil and natural gas imports and exports;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- capacity of processing, gathering, storage and transportation facilities;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not long-term fixed price contracts. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. Because oil, natural gas and NGLs accounted for approximately 65%, 26%, and 9%, respectively, of our estimated proved reserves as of December 31, 2022, and approximately 67%, 25%, and 8%, respectively, of our 2022 production on an MBoe basis, our financial results are sensitive to movements in oil, natural gas and NGL prices.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, making us vulnerable to risks associated with operating in one geographic area.

Our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a single geographic area, the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico. Unlike other entities that are geographically diversified, we may not have the resources to effectively diversify our operations or benefit from the possible spreading of risks or offsetting of losses. Our lack of diversification may subject us to numerous economic, competitive and regulatory developments, any or all of which may have an adverse impact upon the particular industry in which we operate, and result in our dependency upon a single or limited number of hydrocarbon basins. In addition, the geographic concentration of our properties in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico means that some or all of our properties could be affected should the region experience:

- severe weather, such as hurricanes, winter storms, tornadoes and other adverse climatic conditions;
- delays or decreases in production or the availability of equipment, facilities or services;
- delays or decreases in the availability or capacity to transport, gather or process production;
- changes in the status of pipelines that we depend on for transportation of our production to the marketplace;
- extensive governmental regulation (including regulations that may, in certain circumstances, impose strict liability for pollution damage or require posting substantial bonds to address decommissioning and P&A costs) and interruption or termination of operations by governmental authorities based on environmental, safety or other considerations;
- changes in the regulatory environment such as the guidelines issued by the BOEM related to financial assurance requirements to cover decommissioning obligations for operations on the OCS; and/or

- changes imposed as a result of litigation or by a new Presidential Administration or by Congress in the United States that may result in added restrictions and delays or prohibitions in offshore oil and natural gas exploration and production activities, including with respect to leasing, permitting, site development or operation in federal waters or hydraulic fracturing.

Because all or a number of our properties could experience many of the same conditions at the same time, these conditions may have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

Production periods or relatively short reserve lives for U.S. Gulf of Mexico properties may subject us to higher reserve replacement needs and may impair our ability to reduce production during periods of low oil and natural gas prices.

Substantially all of our operations are in the U.S. Gulf of Mexico. As a result, our reserve replacement needs from new prospects may be greater than those of other oil and natural gas companies with longer-life reserves in other producing areas. Our future oil and natural gas production is highly dependent upon our level of success in finding or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices.

Exploring for, developing or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop or acquire additional reserves or make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. Our need to generate revenues to fund ongoing capital commitments or repay debt may limit our ability to slow or shut-in production from producing wells during periods of low prices for oil and natural gas. We cannot assure you that our future exploitation, exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Further, current market conditions may adversely impact our ability to obtain financing to fund acquisitions, and further lower the level of activity and depressed values in the oil and natural gas property sales market.

Our actual recovery of reserves may substantially differ from our proved reserve estimates.

Estimates of our proved oil and natural gas reserves and the estimated future net cash flows from such reserves are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. Additionally, our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. See Items 1 and 2. Business and Properties—*Summary of Reserves* for further discussion on 2022 changes in estimates of our proved reserves.

You should not assume that any present value of future net cash flows from our proved reserves represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2022 on historical 12-month average prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues are affected by factors such as:

- the amount and timing of capital expenditures and decommissioning costs;
- the rate and timing of production;
- changes in governmental legislation, regulations or taxation;
- volume, pricing and duration of our oil and natural gas hedging contracts;

- supply of and demand for oil and natural gas;
- actual prices we receive for oil and natural gas; and
- our actual operating costs in producing oil and natural gas.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties affects the timing of actual future net cash flows from reserves, and thus their actual present value. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and natural gas industry in general.

At December 31, 2022, approximately 17% of our estimated proved reserves (by volume) were undeveloped and approximately 21% were non-producing. Any or all of our PUD or proved developed non-producing reserves may not be ultimately developed or produced. Furthermore, any or all of our undeveloped and developed non-producing reserves may not be ultimately produced during the time periods we plan or at the costs we budget, which could result in the write-off of previously recognized reserves. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling or waterflood operations. Our reserve estimates include the assumptions that we incur capital expenditures to develop these undeveloped reserves and the actual costs and results associated with these properties may not be as estimated. Any material inaccuracies in these reserve estimates or underlying assumptions materially affects the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our acreage has to be drilled before lease expirations in order to hold the acreage by production. If commodity prices become depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.

Unless production is established as required by the leases covering the undeveloped acres, the leases for such acreage may expire. Our drilling plans for areas not held by production are subject to change based upon various factors. As of December 31, 2022, approximately 51% of our net acreage was undeveloped acres. See Items 1 and 2. Business and Properties—*Acreage* for further discussion. Many of these factors are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. On the acreage that we do not operate, we have less control over the timing of drilling, and therefore there is additional risk of expirations occurring in those acreages.

The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.

The marketability of our production depends upon the availability, proximity, operation and capacity of oil and natural gas gathering systems, pipelines and processing facilities. The lack of availability or capacity of these gathering systems, pipelines and processing facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. The disruption of these gathering systems, pipelines and processing facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. Federal, state, and local regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors change dramatically, the financial impact could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

Lower oil and natural gas prices and other factors in the future may result in ceiling test write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting for our oil and gas operations. Accordingly, we capitalize the costs to acquire, explore for and develop oil and natural gas properties. Under the full cost method of accounting, our capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. A write-down of oil and natural gas properties does not impact cash flows from operating activities, but does reduce net income. The risk that we are required to write-down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, or if estimated future development costs increase. Volatility in commodity prices, poor conditions in the global economic markets and other factors could cause us to record additional write-downs of our oil and natural gas properties and other assets in the future, and incur additional charges against future earnings. Any required write-downs or impairments could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

With respect to our operations in Mexico, our oil and natural gas properties are classified as unproved properties, not subject to amortization. The finalization of the unitization and unit operating agreement, which sets out the terms on which the reservoir will be jointly developed, and the outcome of the dispute with the Government of Mexico over decisions taken by SENER with respect to the Zama discovery, could adversely affect the value of the oil and natural gas assets and result in an impairment of our unevaluated oil and gas properties prior to reaching a final investment decision or of our evaluated properties upon reaching a final investment decision. See Part I, Items 1 and 2. Business and Properties — Upstream Properties — *Mexico — Block 7*.

Continuing or worsening inflationary issues and associated changes in monetary policy may result in increases to the cost of our goods, services and personnel, which in turn could cause our capital expenditures and operating costs to rise.

The U.S. inflation rate has been steadily increasing since 2021 and into 2022. These inflationary pressures have resulted in and may result in additional increases to the costs of our goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise. Sustained levels of high inflation have likewise caused the U.S. Federal Reserve (the “Fed”) and other central banks to increase interest rates multiple times in 2022 and the Fed has indicated its intention to continue to raise benchmark interest rates into 2023 in an effort to curb inflationary pressure on the costs of goods and services across the U.S., which could have the effects of raising the cost of capital and depressing economic growth, either of which—or the combination thereof—could hurt the financial and operating results of our business. To the extent elevated inflation remains, we may experience further cost increases for our operations, including services, labor costs and equipment if our drilling activity increases.

Higher crude oil and natural gas prices may cause the costs of materials and services to continue to rise. We cannot predict any future trends in the rate of inflation, and a significant increase in inflation, to the extent we are unable to recover higher costs through higher crude oil and natural gas prices and revenues, would negatively impact our business, financial condition and results of operations.

We may be unable to pursue our CCS business, either wholly or in significant measure, which could have a material adverse effect on our business, results of operations and financial condition.

Our CCS business strategy envisions the construction and operation of one or more CCS projects within the next two to three years, utilizing anthropogenic CO_2 generated by industrial emitters along the Texas and Louisiana Gulf Coast. See Part I, Items 1 and 2. Business and Properties – Carbon Capture & Sequestration for the four CCS projects that are actively being evaluated. Our goal is that CCS projects, such as these four, will eventually enable us to offset some or all our annual net CO_2 emissions while delivering an economic return. However, the successful development of such projects is dependent on various economic, regulatory and operational factors, and any failure to satisfy, wholly or in significant measure, any of such factors could have a material adverse impact on our business, results of operations and financial condition.

Another emerging financial incentive for CCS projects may be the approximately $1.2 trillion infrastructure bill signed by President Biden in November 2021, which includes a provision for approximately $2.5 billion to expand the U.S. Department of Energy's Carbon Storage Validation and Testing program to include large-scale commercialization of new or expanded carbon sequestration projects and CO_2 transport infrastructure. However, the applicability of the financial incentives in the infrastructure bill to our projects is uncertain at this time and there is no assurance that we would qualify for such incentives in the pursuit of our CCS projects or that such incentives would be adequate for our CCS project needs.

Additionally, successful development of CCS projects in the United States requires that we comply with what we anticipate will be a stringent regulatory scheme requiring that we obtain certain permits applicable to subsurface injection of CO_2 for geologic sequestration. Moreover, as operator of our CCS projects, we must demonstrate and maintain levels of financial assurance sufficient to cover the cost of corrective action, injection well plugging, post injection site care and site closure, and emergency and remedial response. As CCS and carbon management represent an emerging sector, regulations may evolve rapidly, which could impact the feasibility of one or more of our anticipated projects. There is no assurance that we will be successful in obtaining permits or adequate levels of financial assurance for one or more of our CCS projects or that permits can be obtained on a timely basis, whether due to difficulty with the technical demonstrations required to obtain such permits, public opposition or otherwise. Separately, permitting CCS projects also requires obtaining a number of other permits and approvals unrelated to subsurface injection from various U.S. federal and state agencies, such as for air emissions or impacts to environmental, natural, historic or cultural resources resulting from the construction and operation of a CCS facility. To the extent regulatory requirements are imposed, are amended or more stringently enforced, we may incur additional costs in the pursuit of one or more of our CCS projects, which costs may be material or may render any one or more of our CCS projects uneconomical.

Development of successful CCS projects will also require satisfying certain operational factors, such as locating a suitable source of anthropogenic CO_2 and reaching suitable agreements to capture that CO_2. Such agreements are complex and may involve allocation of not only fees but also various credits, incentives and environmental attributes associated with the sequestration of CO_2. Not all emission sources produce sufficiently large quantities of pure or relatively pure streams of CO_2, or have installed equipment to capture such CO_2, so as to be usable in one or more of our CCS projects. As a result, we cannot assure whether we will be able to obtain sufficient quantities of CO_2 from emitters on terms that are acceptable to us, and the failure to do so may have a material impact on our ability to execute our CCS strategy. Additionally, development of successful CCS projects will require infrastructure to transport CO_2 between the source and our CCS sites. In project areas with existing CO_2 transportation pipelines, this may require reaching an agreement on CO_2 transportation with operators of CO_2 pipelines within the regions in which we operate. Inability to reach a suitable agreement may render a project uneconomical or impracticable.

Separately, if no CO_2 pipelines exist in proposed project areas, or if existing pipelines do not extend to one or more of our project sites, we may be required to convert existing pipelines, or build new CO_2 pipelines or lateral connections, which may be subject to various environmental and other permitting requirements as well as third party easements, which may render one or more projects uneconomical. We will also need to build the required equipment on a timely basis and at a cost that is economically viable. Additionally, complex recordkeeping and GHG emissions/sequestration accounting may be required in connection with one or more of our projects, which may increase the costs of such operations. Different methodologies may be required for various regulatory and non-regulatory accounts regarding GHG emissions/sequestration at one or more of our projects, including but not limited to, compliance with the EPA's mandatory Greenhouse Gas Reporting Program. Furthermore, as CCS may be viewed as a pathway to the continued use of fossil fuels, notwithstanding that CO_2 emissions are intended to be captured, there may be organized opposition to CCS, including as it relates to our projects.

In consideration of the above matters, we anticipate, but can provide no assurance, that we will be able to execute upon our CCS business strategy in the future. Any failure by us to achieve such expectations in whole or any significant measure could have a material adverse effect on our business, results of operations and financial condition.

Our inability to qualify for, obtain, monetize or otherwise benefit from Section 45Q tax credits could materially reduce our ability to develop CCS projects and, as a result, may adversely impact our business, results of operations and financial condition.

The successful development of our CCS projects is dependent upon our ability to benefit from certain financial and tax incentives available with respect to CCS projects. The development of CCS projects is incentivized by tax credits provided under Section 45Q of the Internal Revenue Code of 1986, as amended (such credits, "Section 45Q tax credits"), which provides a tax credit for qualified CO_2 that is captured using carbon capture equipment and disposed of in secure geological storage. The amount of Section 45Q tax credits from which we may benefit is dependent upon our ability to satisfy certain wage and apprenticeship requirements, which we cannot assure you that we will satisfy. With respect to the first five tax years a qualifying CCS project is in service, but not beyond December 31, 2032, we may elect a "direct pay" option with respect to available Section 45Q tax credits to efficiently monetize their value (i.e., we may receive a payment for the tax credits through a tax refund as if there had been an overpayment of taxes). Following the period in which the direct pay election is available and for the remaining period in which the applicable Section 45Q tax credits are otherwise available, we may elect to transfer the Section 45Q tax credits to unrelated taxpayers. We cannot assure you that we will be able to efficiently monetize Section 45Q tax credits that are transferred to unrelated taxpayers. We will benefit from Section 45Q tax credits only if we satisfy the applicable statutory and regulatory requirements for obtaining the Section 45Q tax credits, including that we own carbon capture equipment that captures qualified CO_2 that we physically or contractually capture and securely store, or if another party that owns carbon capture equipment elects to pass through Section 45Q tax credits to us, that we dispose of the qualified CO_2 in secure storage. If we are unable to satisfy such statutory and regulatory requirements or otherwise qualify for or obtain the Section 45Q tax credits, our CCS projects may no longer be economically viable and may not be completed. We cannot assure you that we will be successful in satisfying such requirements or otherwise qualifying for or obtaining the Section 45Q tax credits currently available or that we will be able to effectively benefit from such tax credits. Section 45Q tax credits are also subject to recapture with respect to any CO_2 that ceases to be disposed of in secure storage, which recapture is treated as an increase in tax liability for the year in which the recapture occurs. The recapture period for Section 45Q tax credits is limited to a 3-year lookback period preceding the date that sequestered CO_2 escapes from its secure storage.

Additionally, the availability of Section 45Q tax credits may be reduced, modified or eliminated as a matter of legislative or regulatory policy. There can be no assurance that Section 45Q tax credits will not be reduced, modified or eliminated in the future. Any such reduction, modification or elimination of Section 45Q tax credits, or our inability to otherwise benefit from Section 45Q tax credits, could materially reduce our ability to develop CCS projects and, as a result, may adversely impact our business, results of operations and financial condition. Even if we are able to benefit from Section 45Q tax credits, we may determine that additional financial incentives are required for our CCS projects to be economically viable. If such additional incentives do not emerge, we may not be able to achieve an economic return from our CCS business or, alternatively, the construction or operation of our CCS projects may be substantially delayed, unprofitable or otherwise infeasible.

Our business could be negatively affected by security threats, including cybersecurity threats, terrorist attacks and other disruptions.

As an oil and gas producer, we have various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business. In particular, the implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls are sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments subject our operations to increased risks. Any future terrorist attack at our facilities, or those of our purchasers or vendors, could have a material adverse effect on our financial condition and operations.

Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business.

We face risks related to epidemics, outbreaks or other public health events that are outside of our control, and could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to our business and operational plans, which may include (i) shortages of employees, (ii) unavailability of contractors or subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) recommendations of, or restrictions imposed by government and health authorities, including quarantines, to address an outbreak and (v) restrictions that we and our contractors, subcontractors and our customers impose, including facility shutdowns, to ensure the safety of employees.

In addition, the effects of COVID-19 and concerns regarding its global spread could negatively impact the domestic and international demand for crude oil and natural gas, which could contribute to price volatility, impact the price we receive for oil and natural gas and materially and adversely affect the demand for and marketability of our production. The potential impact from COVID-19, both now and in the future, is difficult to predict, and the extent to which it may negatively affect our operating results or the duration of any potential business disruption is uncertain. Any potential impact will depend on future developments and new information that may emerge regarding the COVID-19 infection rate or the efficacy and distribution of COVID-19 vaccines, and the actions taken by authorities to contain it or treat its impact, all of which are beyond our control. These potential impacts, while uncertain, could adversely affect our operating results.

The ongoing war between Russia and Ukraine could adversely affect our business, financial condition and results of operations.

On February 24, 2022, Russian military forces invaded Ukraine, and sustained war and disruption in the region is likely. Although the length, impact and outcome of the ongoing military war in Ukraine is highly unpredictable, this war could lead to significant market and other disruptions, including significant volatility in commodity prices and supply of energy resources, instability in financial markets, supply chain interruptions, political and social instability, changes in consumer or purchaser preferences as well as increases in cyberattacks and espionage.

Russia’s recognition of two separatist republics in the Donetsk and Luhansk regions of Ukraine and subsequent military action against Ukraine have led to an unprecedented expansion of sanction programs imposed by the U.S., the European Union, the United Kingdom, Canada, Switzerland, Japan and other countries against Russia, Belarus, the Crimea Region of Ukraine, the so-called Donetsk People’s Republic and the so-called Luhansk People’s Republic, including, among others:

- blocking sanctions against some of the largest state-owned and private Russian financial institutions (and their subsequent removal from the Society for Worldwide Interbank Financial Telecommunication payment system) and certain Russian businesses, some of which have significant financial and trade ties to the European Union;
- blocking sanctions against Russian and Belarusian individuals, including the Russian President, other politicians and those with government connections or involved in Russian military activities; and
- blocking of Russia’s foreign currency reserves as well as expansion of sectoral sanctions and export and trade restrictions, limitations on investments and access to capital markets and bans on various Russian imports.

In retaliation against new international sanctions and as part of measures to stabilize and support the volatile Russian financial and currency markets, the Russian authorities also imposed significant currency control measures aimed at restricting the outflow of foreign currency and capital from Russia, imposed various restrictions on transacting with non-Russian parties, banned exports of various products and other economic and financial restrictions. The situation is rapidly evolving as a result of the war in Ukraine, and the U.S., the European Union, the United Kingdom and other countries may implement additional sanctions, export controls or other measures against Russia, Belarus and other countries, regions, officials, individuals or industries in the respective territories. Such sanctions and other measures, as well as the existing and potential further responses from Russia or other countries to such sanctions, tensions and military actions, could adversely affect the global economy and financial markets and could adversely affect our business, financial condition and results of operations.

We are actively monitoring the situation in Ukraine and assessing its impact on our business, including our business partners and customers. To date we have not experienced any material interruptions in our infrastructure, supplies, technology systems or networks needed to support our operations. We have no way to predict the progress or outcome of the war in Ukraine or its impacts in Ukraine, Russia or Belarus as the war, and any resulting government reactions, are rapidly developing and beyond our control. Continued hostilities, or any significant increases in the extent and duration of the military action, sanctions and resulting market disruptions — or any meaningful escalation in the objectives thereof or the methods used by the combatants to achieve such objectives —could be significant and could potentially have substantial impact on the global economy and our business for an unknown period of time.

Alternatively, a cessation of hostilities as a result of a negotiated withdrawal or otherwise—particularly if coupled with an easing of international sanctions — could cause commodity prices to decline in a manner that would reduce the revenues we receive for our oil and gas production. During the first quarter of 2022, we experienced an increase in commodity prices as sanctions imposed on Russia severely limited the access of Russian oil and gas producers to international markets. In the months that followed, commodity prices subsequently decreased and remained stagnant during the second half of 2022. If the military action concludes and the related sanctions are dropped, commodity prices could significantly decrease. Any of the abovementioned factors could affect our business, financial condition and results of operations.

New technologies may cause our current exploration and drilling methods to become obsolete, and we may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and that may in the future, allow them to implement new technologies before we can. We rely heavily on the use of seismic technology to identify low-risk development and exploitation opportunities and to reduce our geological risk. Seismic technology or other technologies that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

We may not be in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves from our non-operated properties.

As we carry out our drilling program, we may not serve as operator of all planned wells. For example, in March 2022, the final UR from SENER regarding the development of the Zama Field in offshore Mexico, affirmed the appointment of PEMEX as operator of the unit, despite our discovery of the Zama Field in 2017 and subsequent operatorship. We may have limited ability to exercise influence over the operations of some non-operated properties and their associated costs. Our dependence on the operator and other working interest owners, and our limited ability to influence operations and associated costs of properties operated by others, could prevent the realization of anticipated results in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depends upon a number of factors that could be largely outside of our control, including:

- the timing and amount of capital expenditures;

- the availability of suitable offshore drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- risk of other non-operator's failure to pay its share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs;
- selection of technology;
- the rate of production of the reserves; and
- the timing and cost of P&A operations.

In addition, with respect to oil and natural gas projects that we do not operate, we have limited influence over operations, including limited control over the maintenance of safety and environmental standards. The operators of those properties may, depending on the terms of the applicable joint operating agreement:

- refuse to initiate exploration or development projects;
- initiate exploration or development projects on a slower or faster schedule than we would prefer;
- delay the pace of exploratory drilling or development; and/or
- drill more wells or build more facilities on a project than we can afford, whether on a cash basis or through financing, which may limit our participation in those projects or limit the percentage of our revenues from those projects.

The occurrence of any of the foregoing events could have a material adverse effect on our anticipated exploration and development activities.

Hedging transactions may limit our potential gains.

In order to manage our exposure to price risks in the marketing of our oil, natural gas and NGLs, we periodically enter into oil, natural gas and NGLs price hedging arrangements with respect to a portion of our expected production. These arrangements may include futures contracts on the NYMEX. While intended to reduce the effects of volatile oil and natural gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected or is shut-in for extended periods due to hurricanes or other factors;
- there is a widening of price differentials between delivery points for our production and the delivery point to be assumed in the hedge arrangement;
- the counterparties to our futures contracts fails to perform the contracts;
- a sudden, unexpected event materially impacts oil or natural gas prices; or
- we are unable to market our production in a manner contemplated when entering into the hedge contract.

Our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our Bank Credit Facility. Our derivative agreements with the lenders are secured by the security documents executed by the parties under the Bank Credit Facility. Future collateral requirements for our commodity hedging activities are uncertain and depend on the arrangements we negotiate with the counterparty and the volatility of oil and natural gas prices and market conditions.

Our operations may incur substantial liabilities to comply with environmental laws and regulations as well as legal requirements applicable to marine mammals and endangered and threatened species.

Our oil and natural gas operations in the United States and Mexico are subject to stringent federal, state and/or local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations require the acquisition of a permit or other approval before drilling or other regulated activity commences; restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; limit or prohibit exploration or drilling activities on certain lands lying within protected areas or that may affect certain wildlife, including marine species and endangered and threatened species and impose substantial liabilities for pollution resulting from our operations. Additionally, the threat of climate change continues to attract considerable attention in the United States and in foreign countries and the combat of climate change has been made a focal point of the Biden Administration's agenda. See Part I, Items 1 and 2. Business and Properties — Government Regulation — *Environmental and Occupational Safety and Health Regulations* for more discussion on environmental and worker safety matters. One or more of these developments that impact our oil and natural gas exploration and production activities on the OCS could have a material adverse effect on our business, results of operations and financial condition.

Additional drilling laws, regulations, executive orders and other regulatory initiatives that restrict, delay or prohibit oil and natural gas exploration, development and production activities or access to locations where such activities may occur could have a material adverse effect on our business, financial condition or results of operations.

The Biden Administration has taken a number of actions that may result in stricter environmental, health and safety standards applicable to our operations and those of the oil and gas industry more generally. The Biden Administration issued the "Executive Order on Tackling the Climate Crisis at Home and Abroad" on January 27, 2021 (the "Climate Change Executive Order"). This executive order directed the Secretary of the Interior to halt indefinitely new oil and natural gas leases on federal lands and offshore waters pending completion of a review by the Secretary of the Interior of federal oil and gas permitting and leasing practices in light of the Biden Administration's concerns regarding the impact of these activities on the environment and climate. The Secretary of the Interior completed its review of permitting and leasing practices in November 2021 and issued a report recommending, among other things, an increase in royalty rates and financial assurance requirements. However, litigation concerning the Climate Change Executive Order's pause on new oil and gas leases is ongoing. In June 2021, the U.S. District Court for the Western District of Louisiana issued a nationwide preliminary injunction barring the Biden Administration from implementing the pause in new federal oil and gas leases, an injunction which was made permanent in August 2022. This effectively halts implementation of the leasing suspension with respect to those lease sales canceled or postponed prior to March 24, 2021. In November 2021, the Biden Administration conducted an offshore lease sale and various industry participants submitted bids for leases in the Gulf of Mexico; however, on January 27, 2022, in litigation brought by Friends of the Earth and other plaintiffs, the U.S. District Court for the District of Columbia vacated the November 2021 lease sale and the related agency decision making process, finding that the BOEM failed to consider the impact on foreign greenhouse gas emissions if the November 2021 lease sale was not held and the court determined that this failure was a violation of the NEPA. In September 2022, BOEM announced that it was reinstating the lease results in line with congressional direction in the IRA 2022. In addition, there is increasing uncertainty regarding the near-term future of Gulf of Mexico lease sales. These lease sales are conducted pursuant to Five-Year Leasing Programs under the Outer Continental Shelf Lands Act. The most recent Five-Year Leasing Program expired on June 30, 2022 and on July 1, 2022, BOEM released a proposed program for 2023 through 2028. The proposed program, which was subject to public comment through October 6, 2022, proposes no more than ten potential lease sales in the Gulf of Mexico. However, until a final program decision is made and approved—which can take two to three years to complete—no new Gulf of Mexico lease sales can be held. Consequently, it is uncertain whether a new Five-Year Leasing Program will be finalized and subsequent lease sales will be conducted during the current Biden Administration. Additionally, the new Five-Year Leasing Program will likely be subject to heightened environmental review. It is also possible that the program could be delayed if opponents of offshore oil and gas production initiate lawsuits challenging BOEM's actions. Future actions taken by the Biden Administration to limit the availability of new oil and gas leases on the OCS would adversely impact the offshore oil and gas industry and impact demand for our products.

Over the past decade, BSEE and BOEM, primarily under the Obama Administration, have imposed new and more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. While actions by BSEE or BOEM under the Trump Administration sought to mitigate or delay certain of those more rigorous standards, the Biden Administration could reconsider rules and regulatory initiatives implemented under the previous administration and replace them with more stringent requirements and also provide more rigorous enforcement of existing regulatory requirements. Compliance with any added or more stringent regulatory requirements or enforcement initiatives and existing environmental and spill regulations, together with uncertainties or inconsistencies in decisions and rulings by governmental agencies and delays in the processing and approval of drilling permits and exploration, development, oil spill response and decommissioning plans could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts. Moreover, governmental agencies under the Biden Administration may continue evaluating aspects of safety and operational performance in the U. S. Gulf of Mexico that may result in new, more restrictive requirements.

These regulatory actions, or any new laws, executive orders, regulations or other legal or enforcement initiatives, that impose increased costs or more stringent operational standards could delay or disrupt our operations, result in increased supplemental bonding and associated costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in suspension or cancellation of leases. Also, if material spill incidents were to occur in the future, the United States or other countries where such an event may occur could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and natural gas exploration and development, any of which could have a material adverse effect on our business. We cannot predict with any certainty the full impact of any new laws or regulations on our drilling and production operations or on the cost or availability of insurance to cover some or all of the risks associated with such operations.

See Part I, Items 1 and 2. Business and Properties — Government Regulation — *OCS Regulation* for more discussion on orders and regulatory initiatives impacting the oil and natural gas industry on the OCS.

We may be unable to provide the financial assurances in the amounts and under the time periods required by the BOEM if it submits future demands to cover our decommissioning obligations. If in the future the BOEM issues orders to provide additional financial assurances and we fail to comply with such future orders, the BOEM could elect to take actions that would materially adversely impact our operations and our properties, including commencing proceedings to suspend our operations or cancel our federal offshore leases.

The BOEM requires that lessees demonstrate financial strength and reliability according to its regulations or provide acceptable financial assurances to assure satisfaction of lease obligations, including decommissioning activities on the OCS. In 2016, the BOEM under the Obama Administration had sought to implement more stringent and costly standards under the existing federal financial assurance requirements through issuance and implementation of the 2016 NTL, but former President Trump's Administration first suspended, and then in 2020 rescinded, the implementation of this NTL. Consistent with recommendations made in a November 2021 DOI report on the federal oil and gas leasing program, the Biden Administration could pursue more stringent financial assurance requirements that could increase our operating costs.

Following the effectiveness of the 2016 NTL, we received orders from the BOEM in late 2016 directing us to provide additional financial assurance in material amounts relating to our OCS properties. We entered into discussions with the BOEM regarding the requested additional financial security and submitted a proposed tailored plan (applicable to our sole and non-sole liability properties) for the posting of additional financial security to the agency for review. However, as the Trump Administration rescinded the 2016 NTL, the BOEM withdrew the previously issued orders under the 2016 NTL.

In August 2021, the BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable requirements related to financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM. In connection with this Note to Stakeholders, BOEM initially assessed the required financial assurance for our sole liability properties as approximately $70 million. However, following the opportunity to review BOEM's sole liability assessment, we were able to reduce the financial assurance required to approximately $37.7 million. The bonds covering this amount were posted in 2021.

Notwithstanding the above, the BOEM, now under the Biden Administration, could, in the future, continue to make new demands for additional financial assurances in material amounts relating to the decommissioning of our OCS properties. The BOEM may reject our proposals to satisfy any such additional financial assurance coverage and make demands that exceed our capabilities.

If we fail to comply with the current or future orders of the BOEM to provide additional surety bonds or other financial assurances, the BOEM could commence enforcement proceedings or take other remedial action, including assessing civil penalties, suspending operations or production, or initiating procedures to cancel leases, which, if upheld, would have a material adverse effect on our business, properties, results of operations and financial condition.

In the event that the BOEM issues a new NTL or proposes and finalizes new regulations similar to or more stringent than the 2016 NTL, the likely result could include the loss of supplemental bonding waivers for a large number of operators on the OCS, which could in turn force these operators to seek additional surety bonds and could, consequently, challenge the surety bond market's capacity for providing such additional financial assurance. Operators who have already leveraged their assets as a result of the declining oil market could face difficulty obtaining surety bonds because of concerns the surety companies may have about the priority of their lien on the operator's collateral. Moreover, a depressed oil price environment could result in sureties seeking additional collateral to support existing bonds, such as cash or letters of credit, and we cannot provide assurance that we will be able to satisfy collateral demands for future bonds to comply with supplemental bonding requirements of the BOEM. If we are required to provide collateral in the form of cash or letters of credit, our liquidity position could be negatively impacted and we may be required to seek alternative financing. To the extent we are unable to secure adequate financing, we may be forced to reduce our capital expenditures. All of these factors may make it more difficult for us to obtain the financial assurances required by the BOEM to conduct operations on the OCS. These and other changes to BOEM bonding and financial assurance requirements could result in increased costs on our operations and consequently have a material adverse effect on our business and results of operations.

Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local governmental regulations that materially affect our operations.

Our oil and gas operations are subject to various international, foreign and U.S. federal, state and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions. Regulated matters include: permits for exploration, development and production operations; limitations on our drilling activities in environmentally sensitive areas, such as marine habitats, and restrictions on the way we can discharge materials and/or GHG emissions into the environment; bonds or other financial responsibility requirements to cover drilling contingencies, well P&A and other decommissioning costs; reports concerning operations, the spacing of wells and unitization and pooling of properties; regulations regarding the rate, terms and conditions of transportation service or the price, terms, and conditions related to the purchase and sale of oil and natural gas; and taxation. Failure to comply with these laws and regulations can result in the assessment of administrative, civil or criminal penalties, the issuance of remedial obligations and the imposition of injunctions limiting or prohibiting certain of our operations. In addition, because we hold federal leases, the federal government requires that we comply with numerous additional regulations applicable to government contractors.

The SENER has promulgated guidelines to establish procedures for conducting the unitization of shared reservoirs and approving the terms and conditions of unitization and unit operating agreements, as well as the authority to direct parties holding rights in a potentially shared reservoir to appraise and potentially form a unit for development of such reservoir.

Even with the final regulations in place, there are still some uncertainties regarding the unitization process, specifically relating to Block 7 offshore Mexico. In July 2021, SENER designated PEMEX as operator of the Zama unit, just three days after SENER received a letter directly from PEMEX arguing for operatorship. Under Mexico's own unitization guidelines, SENER was required to "consider the principles of economy, competitiveness, efficiency, legality, transparency, best practices of industry and the best use of hydrocarbons." In September 2021, we submitted Notices of Dispute to the Government of Mexico relating to the decision taken by SENER. Our aim is to resolve the dispute amicably through consultations and negotiations to achieve a fair and mutually beneficial agreement; however, the outcome of these Notices of Dispute could be adverse to us and affect the value that we are able to recognize from the reservoir discovery.

If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online, and will be unable to predict the production levels of such wells once brought back online.

If we are forced to shut-in production, we will likely incur greater costs to bring the associated production back online. Cost increases necessary to bring the associated wells back online may be significant enough that such wells would become uneconomic at low commodity price levels, which may lead to decreases in our proved reserve estimates and potential impairments and associated charges to our earnings. If we are able to bring wells back online, there is no assurance that such wells will be as productive following recommencement as they were prior to being shut-in. Any shut-in or curtailment of the oil, natural gas and NGLs produced from our fields could adversely affect our financial condition and results of operations.

Our operations may be adversely affected by political and economic circumstances in the countries in which we operate.

Our oil and gas exploration, development and production activities are subject to political and economic uncertainties (including but not limited to changes, sometimes frequent or marked, in energy policies or the personnel administering them), expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to acts of terrorism, piracy, disease, illegal cartel activities and other political risks, including tension and confrontations among political parties. Some of these risks may be higher in the developing countries in which we conduct our activities, namely, Mexico. Mexico's most recent presidential election was held in July 2018. Presidential reelection is not permitted in Mexico. President Andrés Manuel López Obrador was elected to a six-year term, took office on December 1, 2018, and his political party, Movimiento Regeneración Nacional has a majority in both houses of Mexico's congress. Mr. Lopez Obrador, and certain members of his cabinet have, in the past, made statements that would call into question the degree of support their administration will have for Mexico's energy reforms. However, at this time we cannot predict what changes (if any) will result from this change in administration. Political events in Mexico could adversely affect economic conditions and/or the oil and gas industry and, by extension, our results of operations and financial position.

We may experience significant shut-ins and losses of production due to the effects of tropical storms and hurricanes in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico.

Our production is primarily associated with our properties in the U.S. Gulf of Mexico and in the shallow waters off the coast of Mexico. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. We are particularly vulnerable to significant risk from hurricanes and tropical storms in the U.S. Gulf of Mexico. We are unable to predict what impact future hurricanes and tropical storms might have on our future results of operations and production.

We are not insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational loss-related events. We have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of well, named U.S. Gulf of Mexico windstorm, oil pollution, construction all risk, workers' compensation and employers' liability and other coverage. Our insurance coverage includes deductibles that have to be met prior to recovery, as well as sub-limits or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences, damages or losses. See Part I, Items 1 and 2. Business and Properties – *Insurance Matters* for more information on our insurance coverage.

An operational or hurricane or other adverse weather-related event may cause damage or liability in excess of our coverage that might severely impact our financial position. We may be liable for damages from an event relating to a project in which we own a non-operating working interest. Such events may also cause a significant interruption to our business, which might also severely impact our financial position. We may experience production interruptions for which we do not have production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the U.S. Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

SEC rules could limit our ability to book additional PUD reserves in the future.

SEC rules require that, subject to limited exceptions, PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement may limit our ability to book additional PUD reserves as we pursue our drilling program. Moreover, we may be required to write down our PUD reserves if we do not drill those wells within the required five-year timeframe.

Our actual production could differ materially from our forecasts.

From time to time, we may provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts may assume that none of the risks associated with our oil and natural gas operations summarized in this section would occur, such as facility or equipment malfunctions, adverse weather effects, adverse resolutions to disputes relating to operatorships (such as that observed with the Zama Field dispute) or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

Our operations are subject to numerous risks of oil and natural gas drilling and production activities.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves are found. The cost of drilling and completing wells is often uncertain. To the extent we drill additional wells in the U.S. Gulf of Mexico Deepwater and/or in the Gulf Coast deep shelf, our drilling activities increase capital cost. In addition, the geological complexity of the areas in which we have oil and natural gas operations make it more difficult for us to sustain the historical rates of drilling success. Oil and natural gas drilling and production activities may be shortened, delayed or cancelled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- hurricanes and other adverse weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services. We cannot assure you that the wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry holes and wells that are productive but do not produce sufficient cash flows to recoup drilling costs.

Our industry experiences numerous operating risks.

The exploration, development and production of oil and gas properties involves a variety of operating risks, including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. We are also involved in completion operations that utilize hydraulic fracturing, which may potentially present additional operational and environmental risks. Additionally, our offshore operations are subject to the additional hazards of marine operations, such as capsizing, collisions and adverse weather and sea conditions, including the effects of hurricanes.

In addition, an oil spill on or related to our properties and operations could expose us to joint and several strict liability, without regard to fault, under applicable law for containment and oil removal costs and a variety of public and private damages, including, but not limited to, the costs of responding to a release of oil, natural resource damages and economic damages suffered by persons adversely affected by an oil spill. If an oil discharge or substantial threat of discharge were to occur, we could be liable for costs and damages, which costs and damages could be material to our results of operations and financial position.

Our business is also subject to the risks and uncertainties normally associated with the exploration for and development and production of oil and natural gas that are beyond our control, including uncertainties as to the presence, size and recoverability of hydrocarbons. We may not encounter commercially productive oil and natural gas reservoirs. We may not recover all or any portion of our investment in new wells. The presence of unanticipated pressures or irregularities in formations, miscalculations or accidents may cause our drilling activities to be unsuccessful and/or result in a total loss of our investment, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, we may be uncertain as to the future cost or timing of drilling, completing and operating wells.

We have an interest in Deepwater fields and may attempt to pursue additional operational activity in the future and acquire additional fields and leases in the Deepwaters of the U.S. Gulf of Mexico. Exploration for oil or natural gas in the Deepwaters of the U.S. Gulf of Mexico generally involves greater operational and financial risks than exploration in the shallower waters of the U.S. Gulf of Mexico conventional shelf. Deepwater drilling generally requires more time and more advanced drilling technologies, involving a higher risk of technological failure and usually higher drilling costs. For example, the drilling of Deepwater wells requires specific types of drilling rigs with significantly higher day rates and limited availability as compared to the rigs used in shallower water. Deepwater wells often use subsea completion techniques with subsea trees tied back to host production facilities with flow lines. The installation of these subsea trees and flow lines requires substantial time and the use of advanced remote installation mechanics. These operations may encounter mechanical difficulties and equipment failures that could result in cost overruns. Furthermore, the Deepwater operations generally lack the physical and oilfield service infrastructure present in the shallower waters of the U.S. Gulf of Mexico conventional shelf. As a result, a considerable amount of time may elapse between a Deepwater discovery and the marketing of the associated oil or natural gas, increasing both the financial and operational risk involved with these operations. Because of the lack and high cost of infrastructure, some reserve discoveries in the Deepwater may never be produced economically.

If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations and production and repairs to resume operations. Any of these industry operating risks could have a material adverse effect on our business, results of operations and financial condition.

Competition within our industry may adversely affect our operations.

Competition within our industry is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than our budget, which may adversely affect our ability to compete. If other companies relocate to the U.S. Gulf of Mexico region, levels of competition may increase and our business could be adversely affected. In the exploration and production business, some of the larger integrated companies may be better able than we are to respond to industry changes including price fluctuations, oil and gas demand, political change and government regulations.

We actively compete with other companies when acquiring new leases or oil and gas properties. For example, new leases acquired from the BOEM are acquired through a “sealed bid” process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. The competitors may also have a greater ability to continue drilling activities during periods of low oil and gas prices and to absorb the burden of current and future governmental regulations and taxation. Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to pay more for productive oil and gas properties and exploratory prospects than we are able or willing to pay. Further, our competitors may be able to expend greater resources on the existing and changing technologies that we believe impacts attaining success in the industry. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

The loss of our larger customers could materially reduce our revenue and materially adversely affect our business, financial condition and results of operations.

We have a limited number of customers that provide a substantial portion of our revenue. The loss of our larger customers, including Shell Trading (US) Company, Valero Energy Corporation and Chevron Products Company, could adversely affect our current and future revenue, and could have a material adverse effect on our business, financial condition and results of operations.

The loss of key personnel could adversely affect our ability to operate.

Our industry has lost a significant number of experienced professionals over the years due to its cyclical nature, which is attributable, among other reasons, to the volatility in commodity prices. Our operations are dependent upon key management and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us and our operations.

In addition, our exploration, production and decommissioning activities require personnel with specialized skills and experience. As a result, our ability to remain productive and profitable depends upon our ability to employ and retain skilled workers. Our ability to expand operations depends in part on our ability to increase the size of our skilled labor force, including geologists and geophysicists, field operations managers and engineers, to handle all aspects of our exploration, production and decommissioning activities. The demand for skilled workers in our industry is high, and the supply is limited. A significant increase in the wages paid by competing employers or the unionization of our U.S. Gulf of Mexico employees could result in a reduction of our labor force, increases in the wage rates that we will have to pay, or both. If either of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

We have operations in multiple jurisdictions, including jurisdictions in which the tax laws, their interpretation or their administration may change. As a result, our tax obligations and related filings are complex and subject to change, and our after-tax profitability could be lower than anticipated. Additionally, future tax legislative or regulatory changes in the United States, Mexico or any other jurisdiction in which we operate or have subsidiaries could result in changes to the taxation of our income and operations, which could also adversely impact our after-tax profitability.

We are subject to income, withholding and other taxes in the United States on a worldwide basis and in numerous state, local and foreign jurisdictions with respect to our income, operations and subsidiaries in those jurisdictions. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions, refunds (including refunds of value added taxes) and other benefits to reduce our tax liabilities, changes in the relative amount of our earnings subject to tax in the various jurisdictions in which we operate or have subsidiaries, the potential expansion of our business into or otherwise becoming subject to tax in additional jurisdictions, changes to our existing business structure and operations, the extent of our intercompany transactions and the extent to which taxing authorities in the relevant jurisdictions respect those intercompany transactions.

Our after-tax profitability may also be affected by changes in the relevant tax laws and tax rates, regulations, administrative practices and principles, judicial decisions, and interpretations, in each case, possibly with retroactive effect. From time to time, federal and state level legislation in the United States has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently available to oil and natural gas exploration and development companies. Such proposed legislative changes have included, but have not been limited to, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies, and (v) an increase in the U.S. federal income tax rate applicable to corporations (such as us). U.S. states in which we operate or own assets may also impose new or increased taxes or fees on oil and natural gas extraction. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent Base Erosion and Profit Shifting (the "Multilateral Instrument") has entered into force among the jurisdictions that have ratified it, although the United States has not yet become a signatory to the Multilateral Instrument. Such proposed legislative changes and ratification of the Multilateral Instrument in the jurisdictions in which we operate could result in further changes to our global taxation. Additionally, Mexico has enacted tax reform legislation, and a majority of the provisions became effective on January 1, 2020. These tax reforms provided for new and complex provisions that significantly change how Mexico tax entities and operations and are subject to further legislative change and administrative guidance and interpretation, which may differ from our interpretation. Future tax legislative or regulatory changes in the United States, Mexico or in any other jurisdictions in which we operate now or in the future could also adversely impact our after-tax profitability.

A significant portion of our production, revenue and cash flow is concentrated in our Phoenix Field and our Pompano Field. Because of this concentration, any production problems, impacts of adverse weather or inaccuracies in reserve estimates could have a material adverse impact on our business.

For the year ended December 31, 2022, approximately 21% and 18% of our production and 23% and 19% of our total revenue was attributable to our Phoenix Field and our Pompano Field, respectively, both of which are located in the federal waters offshore in the U.S. Gulf of Mexico. This concentration in these fields means that any impact on our production from these fields, whether because of mechanical problems, adverse weather, well containment activities, changes in the regulatory environment or otherwise, could have a material effect on our business. We produce the Phoenix Field through the HP-I, a dynamically positioned floating production facility that is operated by Helix. The HP-I interconnects the Phoenix Field through a production buoy that can be disconnected if the HP-I cannot maintain its position on station, such as in the event of a mechanical problem with the dynamic positioning system or the approach of a hurricane. Because the HP-I may have to be disconnected from the Phoenix Field if circumstances require, our production from the Phoenix Field may be subject to more frequent interruptions than if the Phoenix Field was produced by a more conventional platform.

We are also required to disconnect and dry-dock the HP-I every two to three years for inspection as required by the United States Coast Guard, during which time we are unable to produce the Phoenix Field. During the year ended December 31, 2022, Helix dry-docked the HP-I. After conducting sea trials, production resumed in mid-September 2022, resulting in a total shut-in period of 41 days. The shut-in resulted in deferred production of 1.6 MBoepd during the year ended December 31, 2022 based on production rates prior to the shut-in.

The HP-I is part of the Helix Well Containment Group ("HWCG"), which is a consortium that is available to respond to any Deepwater well control event, such as the Macondo well oil spill. If such an event were to occur and the HWCG was to be utilized for well control, the HP-I, which is the vessel that would be used to respond to the Deepwater well control event, would be required to disconnect from the Phoenix Field until such time as the well control event was resolved and the HP-I could return to the Phoenix Field. During such time period, we would not be able to produce the Phoenix Field. In the event the HP-I has to disconnect from the Phoenix Field, our production, revenue and cash flow could be adversely affected, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, all of our production from the Phoenix Field flows through the Green Canyon 19 connection facility operated by Shell GOM Pipeline Company LLC. To the extent Shell GOM Pipeline Company LLC temporarily shuts in its Green Canyon 19 connection facility, whether for maintenance or otherwise, we would not be able to produce the Phoenix Field during this period of time, which may have a material adverse effect on our business, financial condition, results of operations and cash flows. If the actual reserves associated with the Phoenix Field are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

In addition, all of our production from the Pompano Field flows through the Pompano Pipeline System operated by Crimson Gulf LLC. To the extent Crimson Gulf LLC temporarily shuts in the Pompano Pipeline System, whether for maintenance or otherwise, we would not be able to produce the Pompano Field during this period of time, which may have a material adverse effect on our business, financial condition, results of operations and cash flows. If the actual reserves associated with the Pompano Field are less than our estimated reserves, such a reduction of reserves could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our Mexican operations are subject to certain offshore regulatory and environmental laws and regulations promulgated by Mexico.

Our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by the SENER, the CNH and other Mexican regulatory bodies. The laws and regulations governing activities in the Mexican energy sector have undergone significant reformation over the past decade, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. See Part I, Items 1 and 2. Business and Properties – Government Regulation – *Regulation in Shallow Waters Off the Coast of Mexico* and Part I, Items 1 and 2. Business and Properties – Government Regulation – *Hydrocarbon Export Regulation in Mexico* for additional disclosure relating to the legal requirements imposed by SENER, CNH or other Mexican regulatory bodies to which we may be subject in the pursuit of our operations.

In addition, our oil and gas operations in shallow waters off the coast of Mexico's Tabasco state are subject to regulation by the ASEA. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are also relatively new, having been significantly reformed in 2013 and 2014, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidance. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. See Part I, Items 1 and 2. Business and Properties – Environmental and Occupational Safety and Health Regulations – *Environmental Regulation in Shallow Waters Off the Coast of Mexico* for additional disclosure relating to the legal requirements imposed by ASEA or other Mexican regulatory bodies to which we may be subject in the pursuit of our operations. The permit holders must comply with requirements relating to insurance, facility construction and design, law compliance, and risk analysis scenarios.

Under the Block 7 PSC, we are also jointly and severally liable for the performance of all obligations under the PSC, including exploration, appraisal, extraction and abandonment activities and compliance with all environmental regulations, and failure to perform such obligations could result in contractual rescission of the PSC.

Three-dimensional seismic interpretation does not guarantee that hydrocarbons are present or if present, produce in economic quantities.

We rely on 3D seismic studies to assist us with assessing prospective drilling opportunities on our properties, as well as on properties that we may acquire. Such seismic studies are merely an interpretive tool and do not necessarily guarantee that hydrocarbons are present or, if present, produce in economic quantities, and seismic indications of hydrocarbon saturation are generally not reliable indicators of productive reservoir rock. These limitations of 3D seismic data may impact our drilling and operational results, and consequently our financial condition.

We may be exposed to liabilities under the U.S. Foreign Corrupt Practices Act (the "FCPA").

We are subject to the FCPA and other laws that prohibit improper payments or offers of payments to foreign governments and their officials and political parties for the purpose of obtaining or retaining business. We may do business in the future in countries and regions in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations or private entities. Thus, we face the risk of unauthorized payments or offers of payments by one of our employees or consultants, given that these parties may not always be subject to our control. Our existing safeguards and any future improvements may prove to be less than effective, and our employees and consultants may engage in conduct for which we might be held responsible.

Under the Block 7 PSC with the CNH, we work as a consortium with our partners. Violations of the FCPA, by any consortium partner, may result in severe criminal or civil sanctions, and we may be subject to other liabilities, which could negatively affect our business, operating results and financial condition. In addition, the CNH has the authority to rescind the PSC if these violations occur.

Our business depends on access to oil and natural gas processing, gathering and transportation systems and facilities.

The marketability of our oil and natural gas production depends in large part on the operation, availability, proximity, capacity and expansion of processing, gathering and transportation facilities owned by third parties. We can provide no assurance that sufficient processing, gathering and/or transportation capacity exists or that we will be able to obtain sufficient processing, gathering and/or transportation capacity on economic terms. A lack of available capacity on processing, gathering and transportation facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these facilities for an extended period of time could negatively impact our revenues. In addition, we enter into contracts for firm transportation, and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above. In addition, the rates charged for processing, gathering and transportation services may increase over time.

Our operations are subject to various risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which oil and natural gas production may occur and reduce demand for the crude oil and natural gas that we produce.

Climate change continues to attract considerable public, political and scientific attention. In the United States, no comprehensive climate change legislation has been adopted at the federal level, but President Biden has indicated that action to address climate change is an important part of his administration's agenda. For example, in August 2022, the IRA 2022 passed which advances numerous climate-related objectives. Numerous other executive actions and legislative and regulatory initiatives have been made or are likely to be considered by his administration and analogous legal actions are likely to be made or considered at the state, regional or international levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. These regulatory efforts have included consideration of cap-and-trade programs, carbon taxes, GHG emissions reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. Additionally, the threat of climate change has resulted in increasing political, litigation and financial risks associated with the production of fossil fuels and emissions of GHGs. Moreover, climate change activism calling for reduced access to capital, fuel conservation measures, governmental initiatives for renewable energy resources, increasing consumer demand for alternative forms of energy, technological advances in fuel economy and energy generation devices may create new competitive conditions that result in reduced demand for the oil and natural gas we produce. Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, rising sea levels and other climatic events. See Part I, Items 1 and 2. Business and Properties – *Environmental and Occupational Safety and Health Regulations – Climate Change* for additional disclosure relating to risks arising out of the threat of climate change.

The adoption of legislation or regulatory programs to reduce or eliminate future emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce or eliminate future emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Also, political, financial and litigation risks may result in our restricting or canceling production activities, incurring liability for infrastructure damages as a result of climatic changes or impairing the ability to continue to operate in an economic manner. Further, if any such effects of climate changes were to occur, they could have an adverse effect on our financial condition and results of operations.

Increasing attention to ESG matters may impact our business.

Increasing attention to climate change, societal expectations on companies to address climate change, and potential consumer use of substitutes to oil and gas commodities may result in increased costs, reduced demand for our products and our services and the products and services of our customers, reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change, for example, may result in demand shifts for the hydrocarbon products we produce as well as additional governmental investigations and private litigation against us. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

The Board of Directors' Safety, Sustainability and Corporate Responsibility Committee is the primary committee of our Board of Directors responsible for overseeing and managing our ESG initiatives. Committee members are expected to meet quarterly to review the implementation and effectiveness of our ESG programs and policies. In 2022, we hired a Director of ESG who is responsible for driving our sustainability initiatives, engaging with stakeholders, benchmarking our ESG data, and evaluating potential and emerging ESG drivers. Additionally, we have set the following aspirational goals to help strengthen our ESG performance: (i) a 30% reduction in GHG emissions intensity by 2025 with a stretch goal of 40%, as compared to our 2018 GHG emissions intensity baseline; and (ii) increased to 20% the ESG metrics component of our management's annual incentive plan, which includes key initiatives aimed at GHG emissions reduction and health and safety performance. We note, however, that our ESG governance structure may not be able to adequately identify or manage ESG-related risks and opportunities, which may include failing to achieve our GHG emissions intensity reduction or other ESG-related aspirational goals, including but not limited to as a result of unforeseen costs or technical difficulties associated with achieving such goals. Moreover, given the evolving nature of GHG emissions accounting methodologies and climate science, it is possible that factors outside of our control could give rise to the need to restate or revise our emissions intensity reduction goals, cause us to miss them altogether, or limit the impact of success of achieving our goals. Additionally, to the extent we meet such targets, they may be achieved through various contractual arrangements, including the purchase of various credits or offsets that may be deemed to mitigate our ESG impact instead of actual changes in our ESG performance. However, we cannot guarantee that there will be sufficient offsets available for purchase given the increased demand from numerous businesses implementing net zero goals, or that the offsets we do purchase will successfully achieve the emissions reductions they represent.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. We and other companies in our industry publish sustainability reports that are made available to investors. Such ratings and reports are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings may lead to increased negative investor sentiment toward us and to the diversion of investment to other industries which could have a negative impact on our stock price and/or our access to and costs of capital. Additionally, certain institutional lenders may decide not to provide funding to us based on ESG concerns, which could adversely affect our financial condition and access to capital for potential growth projects. To the extent ESG matters negatively impact our reputation, we may also be unable to compete as effectively to recruit or retain employees, which may adversely affect our operations.

Furthermore, public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential ESG benefits. For example, in March 2021, the SEC established the Climate and ESG Task Force in the Division of Enforcement to identify and address potential ESG-related misconduct, including greenwashing. Certain non-governmental organizations and other private actors have also filed lawsuits under various securities and consumer protection laws alleging that certain ESG statements, goals or standards were misleading, false, or otherwise deceptive. As a result, we may face increased litigation risk from private parties and governmental authorities related to our ESG efforts. In addition, any alleged claims of greenwashing against us or others in our industry may lead to further negative sentiment and diversion of investments. Additionally, we could face increasing costs as we attempt to comply with and navigate further regulatory ESG-related focus and scrutiny.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, expanded federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC and the SEC have finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this is accomplished.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also requires us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or to take steps to qualify for an exemption to such requirements. Although we expect to continue to qualify for the end-user exception from the mandatory clearing requirements for swaps to be entered into to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to continue to qualify for, and to utilize, the end-user exception from such margin requirements for swaps to be entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we may encounter or reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

In addition, the European Union and other non-U.S. jurisdictions have implemented and continue to implement new regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become directly subject to such regulations and in any event the global derivatives market are affected to the extent that foreign counterparties are affected by such regulations. At this time, the impact of such regulations is not clear.

Negative publicity may adversely impact us.

Media coverage and public statements that insinuate improper actions by us, regardless of their factual accuracy or truthfulness, may result in negative publicity, litigation or governmental investigations by regulators. For example, in September 2021, we experienced negative publicity relating to an oil release in the U.S. Gulf of Mexico, off the coast of Port Fourchon, Louisiana. Although we were a prior lessee of the block in question, had ceased production in the area in 2017 and had removed all pipeline infrastructure by 2019, the resulting publicity may have had a negative impact on us.

Similar or further such negative publicity in the future relating to U.S. Gulf of Mexico operations generally, or our operations specifically, may expose us to adverse consequences. Addressing negative publicity and any resulting litigation or investigations may distract management, increase costs and divert resources. Negative publicity may have an adverse impact on our reputation and the morale of our employees, which could materially adversely affect our business, financial position, results of operations, cash flows, growth prospects and stock price.

A change in the jurisdictional characterization of our FERC-jurisdictional pipelines, tribal or local regulatory agencies or a change in policy by those agencies may result in increased regulation of such asset, which may cause our revenues to decline and operating expenses to increase or delay or increase the cost of expansion projects.

With respect to CKB Petroleum, Inc., which has been granted a waiver of certain portions of the ICA and related regulations by the FERC, should the pipeline's circumstances change, the FERC could, either at the request of other entities or on its own initiative, assert that such pipeline no longer qualifies for a waiver. In the event that the FERC were to determine that CKB Petroleum, Inc. no longer qualified for a waiver, we would likely be required to file a tariff with the FERC, provide a cost justification for the transportation charge and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on the CKB Petroleum, Inc. pipeline could adversely affect our results of operations.

The Inflation Reduction Act of 2022 could accelerate the transition to a low carbon economy and could impose new costs on our operations.

In August 2022, President Biden signed the IRA 2022 into law. The IRA 2022 contains hundreds of billions in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles and supporting infrastructure and carbon capture and sequestration, amongst other provisions. In addition, the IRA 2022 imposes the first ever federal fee on the emission of greenhouse gases through a methane emissions charge. The IRA 2022 amends the federal CAA to impose a fee on the emission of methane from sources required to report their GHG emissions to the EPA, including those sources in the onshore petroleum and natural gas production categories. The methane emissions charge would start in calendar year 2024 at $900 per ton of methane, increase to $1,200 in 2025, and be set at $1,500 for 2026 and each year after. Calculation of the fee is based on certain thresholds established in the IRA 2022. In addition, the multiple incentives offered for various clean energy industries referenced above could further accelerate the transition of the economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives. This could decrease demand for crude oil and natural gas, increase our compliance and operating costs and consequently adversely affect our business.

Risks Related to our Capital Structure and Ownership of our Common Stock

Our debt level and the covenants in our current or future agreements governing our debt, including our Bank Credit Facility and the indenture for our 12.00% Second-Priority Senior Secured Notes, could negatively impact our financial condition, results of operations and business prospects. Our failure to comply with these covenants could result in the acceleration of our outstanding indebtedness.

The terms of the agreements governing our debt impose significant restrictions on our ability to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt;

- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets;
- selling assets;
- guaranteeing other indebtedness;
- entering into agreements that restrict dividends from our subsidiaries to us;
- merging, consolidating or transferring all or substantially all of our assets;
- hedging future production; and
- entering into transactions with affiliates.

Our level of indebtedness, and the covenants contained in the agreements governing our debt, including the Bank Credit Facility and the indenture for our 12.00% Second-Priority Senior Secured Notes due January 2026 (the "12.00% Notes") of Talos Production Inc. (the "Issuer"), have important consequences on our operations, including:

- requiring that we dedicate a substantial portion of our cash flow from operating activities to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures, and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates because debt under our Bank Credit Facility is at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Sustained low oil and natural gas prices have a material and adverse effect on our liquidity position. Our cash flow is highly dependent on the prices we receive for oil and natural gas.

We depend on our Bank Credit Facility for a portion of our future capital needs. We are required to comply with certain debt covenants and certain financial ratios under the Bank Credit Facility. Our borrowing base under the Bank Credit Facility, which is redetermined semi-annually, is based on an amount established by the lenders after their evaluation of our proved oil and natural gas reserve values. If, due to a redetermination of our borrowing base, our outstanding borrowings plus outstanding letters of credit exceed our redetermined borrowing base (referred to as a borrowing base deficiency), we could be required to repay such borrowing base deficiency. Our Bank Credit Facility allows us to cure a borrowing base deficiency through any combination of the following actions: (i) repay amounts outstanding sufficient to cure the borrowing base deficiency within 30 days after the existence of such deficiency; (ii) add additional oil and gas properties acceptable to the banks to the borrowing base and take such actions necessary to grant the banks a mortgage in such oil and gas properties within 30 days after the existence of such deficiency; (iii) pay the deficiency in four equal monthly installments with the first installment due within 30 days after the existence of such deficiency or (iv) any combination of the above. We are required to elect one of the foregoing options within 10 days after the existence of such deficiency.

We may not have sufficient funds to make such repayments. If we do not repay our debt out of cash on hand, we could attempt to restructure or refinance such debt, reduce or delay investments and capital expenditures, sell assets, or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flows from operating activities to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets are available to pay or refinance such debt. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of our debt, including our Bank Credit Facility and the indenture for our 12.00% Notes, may also prohibit us from taking such actions. Factors that affect our ability to raise cash through offerings of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offerings, refinancing or sale of assets. We cannot assure you that any such offerings, restructuring, refinancing or sale of assets would be successfully completed.

A financial crisis may impact our business and financial condition and may adversely impact our ability to obtain funding under our Bank Credit Facility or in the capital markets.

We use our cash flows from operating activities and borrowings under our Bank Credit Facility to fund our capital expenditures, and we rely on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions. As such, we may not be able to access adequate funding under our Bank Credit Facility as a result of (i) a decrease in our borrowing base due to the outcome of a borrowing base redetermination or a breach or default under our Bank Credit Facility, including a breach of a financial covenant or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. We may also face limitations on our ability to access the debt and equity capital markets and complete asset sales, increased counterparty credit risk on our derivatives contracts and requirements by our contractual counterparties to post collateral guaranteeing performance.

In addition, from time to time, we could be required to, or we or our affiliates may seek to, retire or purchase our outstanding debt through cash purchases and/or exchanges for equity or debt, open-market purchases, privately negotiated transactions or other transactions. Such debt repurchase or exchange transactions, if any, will be upon such terms and at such prices as we may determine and will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material. Such transactions may give rise to taxable cancellation of indebtedness income (to the extent the fair market value of the property exchanged, or the amount of cash paid to acquire the outstanding debt, is less than the adjusted issue price of the outstanding debt) and adversely impact our ability to deduct interest expenses in respect of our debt against our taxable income in the future. This could result in a current or future tax liability, which could adversely affect our financial condition and cash flows.

We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.

We spend a substantial amount of capital for the acquisition, exploration, exploitation, development, and production of oil and natural gas reserves. We fund our capital expenditures primarily through operating cash flows, cash on hand and borrowings under our Bank Credit Facility, if necessary. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil and natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment and regulatory, technological and competitive developments. A further reduction in commodity prices may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from our wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our Bank Credit Facility.

If low oil and natural gas prices, operating difficulties, declines in reserves or other factors, many of which are beyond our control, cause our revenues, cash flows from operating activities, and the borrowing base under our Bank Credit Facility to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditure program. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot be sure that additional debt or equity financing will be available, and we cannot be sure that cash flows provided by operations will be sufficient to meet these requirements. For example, the ability of oil and gas companies to access the equity and high yield debt markets has been, and continues to be, significantly limited.

We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. Accordingly, we are dependent upon distributions from Talos Production Inc. to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock.

We are a holding company that has no material assets other than our ownership of the equity interests of Talos Production Inc. We have no independent means of generating revenue. To the extent Talos Production Inc. has available cash, we will cause Talos Production Inc. to make distributions of cash to us, directly and indirectly through our wholly owned subsidiaries, to pay taxes, cover our corporate and other overhead expenses and pay dividends, if any, on our common stock. As we have never declared or paid any cash dividends on our common stock, we anticipate that any available cash, other than the cash distributed to us to pay taxes and cover our corporate and other overhead expenses, will be retained by Talos Production Inc. to satisfy its operational and other cash needs. Accordingly, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Although we do not expect to pay dividends on our common stock, if our board of directors decides to do so in the future, our ability to do so may be limited to the extent Talos Production Inc. is limited in its ability to make distributions to us, including the significant restrictions the agreements governing Talos Production Inc.'s debt impose on the ability of Talos Production Inc. to make distributions and other payments to us. To the extent that we need funds and Talos Production Inc. is restricted from making such distributions under applicable law or regulation or under the terms of our financing agreements, or is otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt — Restrictions Which Limit the Payment of Dividends* for additional information.

Our estimates of future asset retirement obligations may vary significantly from period to period and unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We are required to record a liability for the discounted present value of our asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the U.S. Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased or decreased costs. As a result, we may significantly increase or decrease our estimated asset retirement obligations in future periods. For example, because we operate in the U.S. Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes and other adverse weather conditions. The estimated costs to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimates of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane or other natural disaster. Also, a sustained lower commodity price environment may cause our non-operator partners to be unable to pay their share of costs, which may require us to pay our proportionate share of the defaulting party's share of costs.

We have divested, as assignor, various leases, wells and facilities located in the U.S. Gulf of Mexico where the purchasers, as assignees, typically assume all abandonment obligations acquired. Certain of these counterparties in these divestiture transactions or third parties in existing leases have filed for bankruptcy protection or undergone associated reorganizations and may not be able to perform required abandonment obligations. Under certain circumstances, regulations or federal laws such as the OCSLA could impose joint and several strict liability and require predecessor assignors, such as us, to assume such obligations. As of December 31, 2022, we have accrued $42.1 million and $12.2 million in obligations reflected as “Other current liabilities” and “Other long-term liabilities”, respectively, on the Consolidated Balance Sheets. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* and Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies* for more information.

We may not realize all of the anticipated benefits from our future acquisitions, and we may be unable to successfully integrate future acquisitions.

Our growth strategy will, in part, rely on acquisitions. We have to plan and manage acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. We expect to grow in the future by expanding the exploitation and development of our existing assets, in addition to growing through targeted acquisitions in the U.S. Gulf of Mexico or in other basins. We may not realize all of the anticipated benefits from our future acquisitions, such as increased earnings, cost savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher than expected acquisition and operating costs or other difficulties, inexperience with operating in new geographic regions, unknown liabilities, inaccurate reserve estimates and fluctuations in market prices. In particular, this risk arises in the context of the EnVen Acquisition, which closed on February 13, 2023. See “—Risks Related to our Integration of EnVen into our Business—The failure to successfully integrate our business and operations with EnVen in the expected time frame may adversely affect our future results.”

In addition, integrating acquired businesses and properties involves a number of special risks and unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. These difficulties include, among other things:

- operating a larger organization;
- coordinating geographically disparate organizations, systems and facilities;
- integrating corporate, technological and administrative functions;
- diverting management’s attention from regular business concerns;
- diverting financial resources away from existing operations;
- increasing our indebtedness; and
- incurring potential environmental or regulatory liabilities and title problems.

Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results. The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which decreases the time they have to manage our business. If our management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

Our future acquisitions could expose us to potentially significant liabilities, including P&A liabilities.

We expect that future acquisitions will contribute to our growth. In connection with potential future acquisitions, we may only be able to perform limited due diligence.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future oil and natural gas prices, operating costs and potential environmental, regulatory and other liabilities, including P&A liabilities. Such assessments are inexact and may not disclose all material issues or liabilities. In connection with our assessments, we perform a review of the acquired properties. However, such a review may not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We may be successful in obtaining contractual indemnification for preclosing liabilities, including environmental liabilities, but we expect that we will generally acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. In addition, even if we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and could potentially expose us to unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Resolution of litigation could materially affect our financial position and results of operations.

Resolution of litigation could materially affect our financial position and results of operations. To the extent that potential exposure to liability is not covered by insurance or insurance coverage is inadequate, we may incur losses that could be material to our financial position or results of operations in future periods.

The corporate opportunity provisions in our Second Amended and Restated Certificate of Incorporation could enable others to benefit from corporate opportunities that might not otherwise be available to us.

Subject to the limitations of applicable law, our Second Amended and Restated Certificate of Incorporation, among other things:

- permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested;
- permits our officers or directors who are also officers, directors, employees, managing directors, or other affiliate of a Principal Stockholder (as defined in the Second Amended and Restated Certificate of Incorporation) to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if any of our officers or directors who is also an officer, director, employee, managing director or other affiliate of the Principal Stockholders becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as an director or officer of us), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to any other entity or individual and that director or officer will not be deemed to have acted in a manner inconsistent with his or her fiduciary duty to us or our stockholders.

Any of our directors may vote upon any contract or any other transaction between us and any affiliated corporation without regard to the fact that such person is also a director or officer of such affiliated corporation.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of others.

Our Second Amended and Restated Certificate of Incorporation designates the Court of Chancery of the State of Delaware and, to the extent enforceable, the federal district courts of the United States of America as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our Second Amended and Restated Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, the sole and exclusive forum for (i) any derivative action or proceeding brought on our or our stockholders' behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our current or former directors, officers, employees, agents and stockholders to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL, our Second Amended and Restated Certificate of Incorporation or our Second Amended and Restated Bylaws, (iv) any action as to which the DGCL confers jurisdiction to the Court of Chancery of the State of Delaware, or (v) any other action asserting a claim that is governed by the internal affairs doctrine shall be the Court of Chancery of the State of Delaware. Our Second Amended and Restated Certificate of Incorporation also provides that, to the fullest extent permitted by applicable law, the federal district courts of the U.S. are the exclusive forum for resolving any complaint asserting a cause of action arising under the Securities Act, subject to and contingent upon a final adjudication in the State of Delaware of the enforceability of such exclusive forum provision. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts with respect to suits brought to enforce a duty or liability created by the Securities Act or the rules and regulations thereunder. Accordingly, both state and federal courts have jurisdiction to entertain claims under the Securities Act.

Notwithstanding the foregoing, the exclusive forum provision does not apply to suits brought to enforce any liability or duty created by the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations thereunder. Any person or entity purchasing or otherwise acquiring an interest in any shares of our capital stock shall be deemed to have notice of and to have consented to the forum provisions in our Second Amended and Restated Certificate of Incorporation.

These choice-of-forum provisions may limit a stockholder's ability to bring a claim in a judicial forum that he, she or it believes to be favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits. Alternatively, if a court were to find these provisions of our Second Amended and Restated Certificate of Incorporation inapplicable or unenforceable with respect to one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could materially adversely affect our business, financial condition and results of operations and result in a diversion of the time and resources of our management and board of directors.

While the Delaware courts have determined that choice of forum provisions of this type are facially valid, uncertainty exists as to whether a court would enforce such provision, and as such, a stockholder may nevertheless seek to bring a claim in a venue other than those designated in our exclusive forum provision. In such instance, to the extent applicable, we would expect to vigorously assert the validity and enforceability of our exclusive forum provision. This may require additional costs associated with resolving such action in other jurisdictions and there can be no assurance that the provisions will be enforced by a court in those other jurisdictions.

Future sales, or the perception of future sales, by us or our existing stockholders in the public market following the EnVen Acquisition could cause the market price for our common stock to decline.

The sale of substantial amounts of shares of our common stock in the public market, or the perception that such sales could occur, could harm the prevailing market price of shares of our common stock. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate.

Certain holders of our common stock, including certain significant stockholders of EnVen, are entitled to rights with respect to registration of approximately 34.3 million shares of our common stock (representing approximately 27.1% of the outstanding shares of our common stock) under the Securities Act pursuant to certain registration rights agreements. If these holders of our common stock, by exercising their registration rights, sell a large number of shares, they could adversely affect the market price for our common stock.

Risks Related to our Integration of EnVen Into our Business

The combined company may fail to realize the anticipated benefits of the EnVen Acquisition.

The ultimate success of the EnVen Acquisition will depend on, among other things, our ability to combine each of Talos's and EnVen's businesses in a manner that realizes anticipated synergies and benefits and meets or exceeds the forecasted stand-alone cost savings anticipated by the combined company. We anticipate that we will benefit from significant synergies, based on, among other things, increased scale. If we are not able to successfully achieve these synergies, or the cost to achieve these synergies is greater than expected, then the anticipated benefits of the EnVen Acquisition may not be realized fully or at all or may take longer to realize than expected.

The failure to successfully integrate our business and operations with EnVen in the expected time frame may adversely affect our future results.

It is possible that the integration process of our business with EnVen's could result in the loss of key employees, customers, providers, vendors or business partners, the disruption of either company's or both companies' ongoing businesses, inconsistencies in standards, controls, procedures and policies, potential unknown liabilities and unforeseen expenses, delays, or regulatory conditions or higher than expected integration costs and an overall post-completion integration process that takes longer than originally anticipated. Specifically, the following issues, among others, must be addressed in integrating the operations in order to realize the anticipated benefits of the EnVen Acquisition:

- combining the companies' operations and corporate functions and the resulting difficulties associated with managing a larger, more complex, integrated business;
- combining our business with EnVen in a manner that permits the combined company to achieve any cost savings or operating synergies anticipated to result from the EnVen Acquisition;
- reducing additional and unforeseen expenses such that integration costs are not more than anticipated;
- minimizing the loss of key employees;
- identifying and eliminating redundant functions and assets;
- maintaining existing agreements with customers, providers and vendors or business partners and avoiding delays in entering into new agreements with prospective customers, providers and vendors or business partners; and
- consolidating the companies' operating, administrative and information technology infrastructure.

In addition, at times the attention of certain members of our management and resources may be focused on the integration of the businesses of the two companies and diverted from day-to-day business operations or other opportunities that may have been beneficial to us, which may disrupt our ongoing business.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are named as a party in certain lawsuits and regulatory proceedings arising in the ordinary course of business. We do not expect that these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

On March 23, 2022, the Company entered into a settlement agreement to receive $27.5 million to resolve previously pending litigation, which was filed on October 23, 2017, against a third-party supplier related to quality issues. As part of the settlement agreement, the Company released all of its claims in the litigation.

On May 29, 2020, a lawsuit was filed in the Court of Chancery asserting derivative and class action claims against us relating to the ILX and Castex Acquisition. Specifically, the lawsuit relates to the fairness of the consideration paid for such acquisitions in light of the fact that certain of the sellers are our affiliates. The lawsuit was dismissed during the third quarter of 2021, and the plaintiffs have appealed the dismissal to the Delaware Supreme Court.

On November 11, 2013, two lawsuits were filed, and on November 12, 2013, a third lawsuit was filed, against Stone and other named co-defendants, by the Parish of Jefferson (“Jefferson Parish”), on behalf of Jefferson Parish and the State of Louisiana, in the 24th Judicial District Court for the Parish of Jefferson, State of Louisiana, alleging violations of the State and Local Coastal Resources Management Act of 1978, as amended, and the applicable regulations, rules, orders and ordinances thereunder (collectively, the “CRMA”), relating to certain of the defendants’ alleged oil and gas operations in Jefferson Parish, and seeking to recover alleged unspecified damages to the Jefferson Parish Coastal Zone and remedies, including unspecified monetary damages and declaratory relief, restoration of the Jefferson Parish Coastal Zone and related costs and attorney’s fees. In March and April 2016, the Louisiana Attorney General and the Louisiana Department of Natural Resources, respectively, intervened in the three lawsuits. In connection with Stone’s filing of bankruptcy in December 2016, Jefferson Parish dismissed its claims against Stone in two of the three Jefferson Parish Coastal Zone Management lawsuits without prejudice to refiling; the claims of the Louisiana Attorney General and the Louisiana Department of Natural Resources were not similarly dismissed. The Jefferson Parish lawsuits were removed to the United States District Court for the Eastern District of Louisiana. The plaintiffs moved to remand the lawsuit to the state courts. Plaintiffs’ motions to remand were submitted to the state court for decision in two of the lawsuits on February 15, 2023 and in the third lawsuit on February 16, 2023.

On November 8, 2013, a lawsuit was filed against Stone and other named co-defendants by the Parish of Plaquemines (“Plaquemines Parish”), on behalf of Plaquemines Parish and the State of Louisiana, in the 25th Judicial District Court for the Parish of Plaquemines, State of Louisiana, alleging violations of the CRMA, relating to certain of the defendants’ alleged oil and gas operations in Plaquemines Parish, and seeking to recover alleged unspecified damages to the Plaquemines Parish Coastal Zone and remedies, including unspecified monetary damages and declaratory relief, restoration of the Plaquemines Parish Coastal Zone, and related costs and attorney’s fees. In March and April 2016, the Louisiana Attorney General and the Louisiana Department of Natural Resources, respectively, intervened in the lawsuit. In connection with Stone’s filing of bankruptcy in December 2016, Plaquemines Parish dismissed its claims against Stone without prejudice to refiling; the claims of the Louisiana Attorney General and the Louisiana Department of Natural Resources were not similarly dismissed. In state court, the Plaquemines Parish lawsuit was stayed pending the conclusion of trials in five other cases, also filed in Plaquemines Parish and alleging violations of the CRMA, but not involving Stone. However, subsequently, the Plaquemines Parish lawsuit was removed to the United States District Court for the Eastern District of Louisiana. The plaintiffs have moved to remand the lawsuit to the state courts, but the case was administratively closed in federal court pending the appeal of another case, also filed in Plaquemines Parish and alleging violations of the CRMA, but not involving Stone. That appeal was resolved by the United States Court of Appeals for the Fifth Circuit on December 15, 2022, and on December, 22, 2022, plaintiffs filed a motion in federal court to re-open the lawsuit. The United States Court of Appeals for the Fifth Circuit has not yet ruled on plaintiffs’ motion to re-open.

Legal proceedings are subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation. Accordingly, we cannot currently predict the manner and timing of the resolution of some of these matters and may be unable to estimate a range of possible losses or any minimum loss from such matters. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies* for more information.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuers Purchases of Equity Securities

Market for Common Stock

Our common stock is listed on the NYSE under the symbol "TALO".

Holders of Record

Pursuant to the records of our transfer agent, as of February 21, 2023, there were approximately 282 holders of record of our common stock.

Dividends

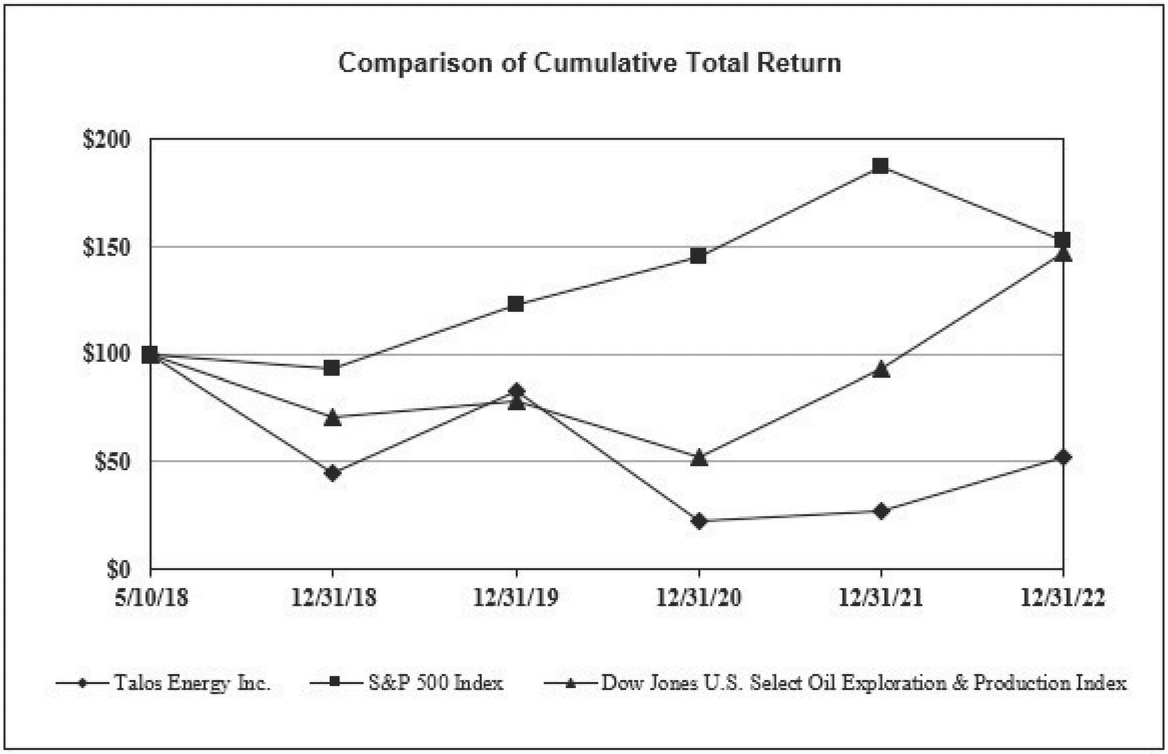
We have never declared or paid any cash dividends on our common stock, and we anticipate that any available cash, other than the cash distributed to us to pay taxes and cover our corporate and other overhead expenses, will be retained by Talos Production Inc. to satisfy its operational and other cash needs. Accordingly, we do not anticipate paying any cash dividends on our common stock in the foreseeable future. Although we do not expect to pay dividends on our common stock, if our board of directors decides to do so in the future, our ability to do so may be limited to the extent Talos Production Inc. is limited in its ability to make distributions to us, including the significant restrictions that the agreements governing Talos Production Inc.'s debt impose on the ability of Talos Production Inc. to make distributions and other payments to us. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt — Limitation on Restricted Payments Including Dividends* for additional information.

Securities Authorized for Issuance Under Equity Compensation Plans

See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" for information regarding securities authorized for issuance under equity compensation plans.

Stockholder Return Performance Presentation

The following graph is included in accordance with the SEC's executive compensation disclosure rules. This historic stock price performance is not necessarily indicative of future stock performance. The graph compares the change in the cumulative total return of our common stock, the Dow Jones U.S. Exploration and Production Index, and the S&P 500 Index for May 10, 2018 through December 31, 2022. The graph assumes that $100 was invested in our common stock and each index on May 10, 2018 and that dividends were reinvested.



	May 10, 2018	2018	2019	2020	2021	2022
Talos Energy Inc.	$ 100	$ 45	$ 83	$ 23	$ 27	$ 52
S&P 500 Index	$ 100	$ 93	$ 123	$ 145	$ 187	$ 153
Dow Jones U.S. Exploration & Production Index	$ 100	$ 71	$ 78	$ 53	$ 93	$ 147

The performance graph and the information contained in this section is not "soliciting material," is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

Item 6. [Reserved]

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on, and should be read in conjunction with our Consolidated Financial Statements and the Notes to Consolidated Financial Statements set forth in Part IV, Item 15. Exhibits and Financial Statement Schedules; Part I, Items 1 and 2. Business and Properties; Part I, Item 1A. Risk Factors; and Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk. This discussion and analysis contains forward-looking statements that involve risk and uncertainties. Actual results may differ materially from those anticipated in these forward-looking statements.

This section of this Annual Report generally discusses 2022 and 2021 items and year-to-year comparisons between 2022 and 2021. Discussions of 2020 items and year-to-year comparisons between 2021 and 2020 that are not included in this Annual Report can be found in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" of the Company's Annual Report on Form 10-K for the year ended December 31, 2021 filed on February 25, 2022.

Our Business

We are a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through our operations, currently in the U.S. and offshore Mexico both through Upstream and the development of CCS opportunities. We leverage decades of technical and offshore operational expertise towards the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. With a focus on environmental stewardship, we also utilize our expertise to explore opportunities to reduce industrial emissions through our CCS initiatives along the Gulf Coast.

We have historically focused our operations in the U.S. Gulf of Mexico because of our deep experience and technical expertise in the basin, which maintains favorable geologic and economic conditions, including multiple reservoir formations, comprehensive geologic and geophysical databases, extensive infrastructure and an attractive and robust asset acquisition market. Additionally, we have access to state-of-the-art three-dimensional seismic data, some of which is aided by new and enhanced reprocessing techniques that have not been previously applied to our current acreage position. We use our broad regional seismic database and our reprocessing efforts to generate a large and expanding inventory of high-quality prospects, which we believe greatly improves our development and exploration success. The application of our extensive seismic database, coupled with our ability to effectively reprocess this seismic data, allows us to both optimize our organic drilling program and better evaluate a wide range of business development opportunities, including acquisitions and collaborative arrangement opportunities, among others.

In order to determine the most attractive returns for our drilling program, we employ a disciplined portfolio management approach to stochastically evaluate all of our drilling prospects, whether they are generated organically from our existing acreage, an acquisition or joint venture opportunities. We add to and reevaluate our inventory in order to deploy capital as efficiently as possible.

Outlook

We know that our investors and other stakeholders' expectations of a successful energy company are evolving. We strive to provide safe, reliable, and responsible energy production that powers our world and delivers energy prosperity to modern life, while simultaneously applying our core skill sets to develop large-scale decarbonization projects to reduce industrial emissions. There are catalysts driving future value creation for both our legacy Upstream business and our emerging CCS business. For example, we plan to fortify, expand and advance our CCS business in 2023 by enhancing our existing portfolio and increasing storage capacity in existing project areas; expand partnerships in existing project areas; progress permitting and front-end engineering design workstreams; advancing and executing commercial contracts; and developing additional point source projects.

Ongoing geopolitical uncertainty will continue to dictate commodity prices, including the ongoing Russia-Ukraine war, production decisions by OPEC Plus and China's evolving policies toward COVID-19. The European Union's ban on seaborne imports of petroleum products from Russia began on February 5, 2023 and could be more disruptive than the ban on crude oil imports implemented on December 5, 2022.

U.S. inflation rates rose to their highest levels since the 1980s last year, due to a string of geopolitical tensions and pandemic-related economic decisions. The Consumer Price Inflation index peaked in June 2022 at 9.0%, then fell for six straight months to 6.5% by the end of the year. The Fed raised interest rates from historic lows with four successive three-quarter point interest rate increases in 2022 and a quarter-point interest rate increase in February 2023. Future interest rate hikes are anticipated in 2023 in order to bring inflation down to the Fed's target of 2.0%. The impact of the interest rate hikes could mean a slower economy, fewer jobs and less spending. The threat for a U.S. recession in 2023 is a reasonable expectation. However, many economists believe a recession, if it were to occur, would be relatively mild. Janet Yellen, U.S. Treasury Secretary, recently expressed confidence that the U.S. can avoid a recession after adding more than 500,000 jobs in January of 2023 that brought unemployment to a 54-year low. In January 2023, the national unemployment rate fell to 3.4%, which is the lowest reading on record since 1969.

Tropical Storm Risk ("TSR"), one of the industry's watched hurricane forecasting teams, issued its extended range forecast for North Atlantic hurricane activity in 2023 anticipating a season with activity below the 1991-2020 30-year norm level. The forecast spans the period from June 1, 2023 to November 30, 2023 and employs data through to the end of November 2022. The TSR is forecasting three intense hurricanes, six hurricanes and 13 tropical storms. TSR's forecast for below-norm activity is due to the warm-neutral or weak El Nino conditions expected through July, August and September of 2023. Despite the expectation for a below-norm hurricane season in 2023, large uncertainties remain.

Significant Developments

The following encompasses significant developments since our Annual Report on Form 10-K for the year ended December 31, 2021:

EnVen Acquisition — On September 21, 2022, we executed a merger agreement to acquire EnVen, a private operator in the Deepwater U.S. Gulf of Mexico (such agreement, the "EnVen Merger Agreement"). The closing of the EnVen Acquisition occurred on February 13, 2023. Consideration for the EnVen Acquisition consisted of (i) $207.3 million in cash and (ii) 43.8 million shares of the Company's common stock valued at $832.2 million. We borrowed $130.0 million from our Bank Credit Facility, of which $119.0 million was used to partially fund the cash portion of the purchase price.

On October 21, 2022, Talos Production Inc. commenced a consent solicitation to obtain the requisite holders' consent to certain amendments to the indenture governing its 12.00% Notes to permit the incurrence of indebtedness with respect to EnVen's 11.75% Senior Secured Second Lien Notes due 2026. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt* for additional information.

Carbon Capture Initiatives — In February 2023, we elected to participate alongside Chevron in an onshore CO_2 sequestration leasehold in southeast Texas. Combined with the offshore Bayou Bend CCS pore space, this participation further expands our CO_2 storage capacity to serve multiple industrial markets within the region. See Part I, Items 1 and 2. Business and Properties — *Carbon Capture & Sequestration* for additional information regarding previously announced projects.

Zama Update — See Part I, Items 1 and 2. Business and Properties — Upstream Properties — *Mexico — Block 7*.

Inflation Reduction Act of 2022 — On August 16, 2022, President Biden signed the IRA 2022 into law. The inclusion of several provisions in the IRA 2022 is expected to benefit both our upstream and CCS businesses. Specifically, the IRA 2022 directs the DOI to:

- accept the highest bids received for Lease Sale 257, which was vacated by the U.S. District Court for the District of Columbia in January 2022; and
- move forward with Lease Sales 259 and 261 in the Gulf of Mexico by March 31, 2023 and September 30, 2023, respectively, notwithstanding the June 30, 2022 expiration of the 2017-2022 Outer Continental Shelf Oil and Gas Leasing Program.

We were one of the most active bidders in Lease Sale 257 and were the high bidder on 10 blocks and awarded leases on 9 blocks. The IRA 2022 also links issuance of federal wind and solar development rights to requirements to offer for sale federal oil and gas leases for a 10-year period of time. The IRA 2022 requires the federal government to offer for sale a minimum of 60 million acres for offshore oil and gas leases during the one-year period immediately preceding granting an offshore wind lease on the U.S. Outer Continental Shelf.

The IRA 2022 incentivizes additional capital investment in CCS projects by developers and sponsors through the following:

- increases the Section 45Q tax credit value from $50 per metric ton to $85 per metric ton of qualified carbon oxide captured from an industrial source and stored in secure geologic formations if certain prevailing wage and apprenticeship requirements are met;
- expands eligibility for carbon capture and sequestration tax credits under Section 45Q by extending the beginning of the construction deadline from before January 1, 2026 to before January 1, 2033; and
- allows taxpayers to now claim the value of a Section 45Q tax credit with respect to carbon capture equipment originally placed in service after December 31, 2022 as a direct pay option (i.e., through a tax refund as if there had been an overpayment of taxes). Both taxable and tax-exempt entities may elect the direct pay option, but any taxable entity may elect such option for only the first 5 years of the tax credit period that is otherwise available.

The IRA 2022 also raises the minimum oil and gas royalty rate for new offshore leases from the current 12.5% to 16.7% and caps the royalty rate at 18.8% for 10 years; however this provision does not affect existing offshore leases. The 18.8% cap is commensurate with the existing offshore royalty rate for leases in water depth exceeding 200 meters.

Additionally, the IRA 2022 imposes a first-ever federal fee on greenhouse gases through a methane emissions charge. The IRA amends the federal Clean Air Act to impose a charge on emissions of methane from sources required to report their GHG emissions to the EPA, including those sources in the offshore and onshore oil and gas production, and onshore processing, transmission and compression, gathering, and boosting station source categories. For such qualifying facilities, the charge starts at $900 per metric ton of methane reported for calendar year 2024, increasing to $1,200 per metric ton of methane for calendar year 2025 and again to $1,500 per metric ton of methane for calendar year 2026 and thereafter. Calculation of the charge is based on certain thresholds established in the IRA 2022. The charge will be based on the prior year's emissions, and the charge starts in 2025 based on 2024 data. The methane emissions charge could increase our operating costs and adversely affect our business.

Factors Affecting the Comparability of our Financial Condition and Results of Operations

The following items affect the comparability of our financial condition and results of operations for periods presented herein and could potentially continue to affect our future financial condition and results of operations.

Planned Downtime — We are vulnerable to downtime events impacting the transportation, gathering and processing of production. We produce the Phoenix Field through the HP-I that is operated by Helix. Helix is required to disconnect and dry-dock the HP-I every two to three years for inspection as required by the U.S. Coast Guard, during which time we are unable to produce the Phoenix Field.

During the year ended December 31, 2022, Helix dry-docked the HP-I. After conducting sea trials, production resumed in mid-September, resulting in a total shut-in period of 41 days. The shut-in resulted in an estimated deferred production of approximately 1.6 MBoepd for the year ended December 31, 2022, based on production rates prior to the shut-in.

During the year ended December 31, 2022, we experienced approximately 26 days of planned third-party downtime due to maintenance of the Shell Odyssey Pipeline, which carries our production primarily from our Ram Powell Field, Main Pass 288 Field and non-operated Delta House facility. Production resumed in October 2022. We estimate the shut-in resulted in deferred production of approximately 0.7 MBoepd for the year ended December 31, 2022, based on production rates prior to the shut-in.

Eugene Island Pipeline System — During the first quarter of 2022, we experienced approximately 40 days of unplanned third-party downtime due to maintenance of the Eugene Island Pipeline System, which carries our production from the Phoenix Field and Green Canyon 18 Field. For the year ended December 31, 2022, we estimate the shut-in has resulted in deferred production of approximately 1.2 MBoepd based on production rates prior to the shut-in.

Hurricanes and Tropical Storms — During 2021, production from the U.S. Gulf of Mexico was impacted due to Hurricane Ida. While our assets did not sustain significant damage, the storm impacted key third-party downstream infrastructure, which prevented us from restoring the majority of our production for several weeks. For the year ended December 31, 2021, we estimate deferred production related to this storm was approximately 4.2 MBoepd, based on production rates prior to the storm. We did not experience any significant disruptions to our operations from hurricanes or tropical storms during the year ended December 31, 2022.

Known Trends and Uncertainties

Volatility in Oil, Natural Gas and NGL Prices — Historically, the markets for oil and natural gas have been volatile. Oil, natural gas and NGL prices are subject to wide fluctuations in supply and demand. Our revenue, profitability, access to capital and future rate of growth depends upon the price we receive for our sales of oil, natural gas and NGL production.

During January 1, 2022 through December 31, 2022, the daily spot prices for NYMEX WTI crude oil ranged from a high of $123.64 per Bbl to a low of $71.05 per Bbl and the daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $9.85 per MMBtu to a low of $3.46 per MMBtu. Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of production. We hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments* for more additional information regarding our commodity derivative positions as of December 31, 2022.

The U.S. Energy Information Administration ("EIA") published its latest Short-Term Energy Outlook on February 7, 2023. The EIA expects the Henry Hub spot price will average $3.40 per MMBtu in 2023. Significantly warmer-than-normal weather in January 2023 led to less-than-normal consumption of natural gas for space heating and pushed inventories above the five-year average. Colder than expected temperatures in February and March 2023 could put upward pressure on prices. The Freeport LNG export facility, which went offline in June 2022 due to a fire, is expected to come back online in the first quarter of 2023 and will likely add over 2 billion cubic feet of natural gas per day of natural gas demand to the U.S. market once fully operational. The EIA also expects the NYEMX WTI spot price will average $77.84 per Bbl in 2023 and $71.57 per Bbl in 2024. In January 2023, the EIA highlighted oil demand in China and oil production in Russia as two of the main uncertainties in the oil market for 2023. China's relaxing COVID-19 restrictions is expected to create oil demand growth. In February 2023, the EIA raised its forecast for Russia's oil production through the end of 2024 but at the same time lowered its forecast for oil production in OPEC because of rising global oil inventories. These production forecast revisions largely offset each other.

Inflation of Cost of Goods, Services and Personnel — Due to the cyclical nature of the oil and gas industry, fluctuating demand for oilfield goods and services can put pressure on the pricing structure within our industry. As commodity prices rise, the cost of oilfield goods and services generally also increase, while during periods of commodity price declines, oilfield costs typically lag and do not adjust downward as fast as oil prices do. In addition, the U.S. inflation rate began increasing in 2021, peaked in the middle of 2022 and began to gradually decline in the second half of 2022. These inflationary pressures may also result in increases to the costs of our oilfield goods, services and personnel, which would in turn cause our capital expenditures and operating costs to rise. Sustained levels of high inflation could likely cause the Fed and other central banks to further increase interest rates, which could have the effects of raising the cost of capital and depressing economic growth, either or both of which could hurt our business. The Fed raised rates again on February 1, 2023, by a quarter of a percentage point to 4.50%-4.75%. The Fed wants inflation to return to their 2% goal over time, and even though inflation is declining, it's still high in absolute terms.

Impairment of Oil and Natural Gas Properties — Under the full cost method of accounting, the "ceiling test" under SEC rules and regulations specifies that evaluated and unevaluated properties' capitalized costs, less accumulated amortization and related deferred income taxes (the "Full Cost Pool"), should be compared to a formulaic limitation (the "Ceiling") each quarter on a country-by-country basis. If the Full Cost Pool exceeds the Ceiling, an impairment must be recorded. During 2022, 2021 and 2020 our ceiling test computations for our U.S. oil and gas properties resulted in a write down of nil, nil and $267.9 million, respectively. At December 31, 2022, the Company's ceiling test computation was based on SEC pricing of $96.03 per Bbl of oil, $6.80 per Mcf of natural gas and $33.89 per Bbl of NGLs.

There is a significant degree of uncertainty with the assumptions used to estimate the present value of future net cash flows from estimated production of proved oil and gas reserves due to, but not limited to the risk factors referred to in Part I, Item 1A. Risk Factors. The discounted present value of our proved reserves is a major component of the Ceiling calculation. Any decrease in pricing, negative change in price differentials, or increase in capital or operating costs could negatively impact the estimated future discounted net cash flows related to our proved oil and natural gas properties.

With respect to our operations in Mexico, our oil and natural gas properties are classified as unproved properties, not subject to amortization. The submission of the Unit Development Plan for the Zama Field to the National Hydrocarbon Commission, which will set out the terms on which the reservoir will be jointly developed, is expected by March 2023 and could adversely affect the value of the Mexico oil and natural gas assets and result in an impairment of our unevaluated oil and gas properties. We recorded an impairment of $18.1 million for our unproved property investment in Block 31 during the year ended December 31, 2021.

BOEM Bonding Requirements — In 2016, the BOEM issued the 2016 NTL, which bolstered supplemental bonding requirements. The 2016 NTL was not fully implemented as the BOEM under the Trump Administration first paused, and then in 2020 rescinded, this NTL.

The future cost of compliance with respect to supplemental bonding, including the obligations imposed on us, whether as current or predecessor lessee or grant holder, as a result of the implementation of a new NTL analogous to the 2016 NTL to the extent finalized, as well as to the provisions of any other new, more stringent NTLs or final rules on supplemental bonding published by the BOEM under the Biden Administration, could materially and adversely affect our financial condition, cash flows and results of operations. Moreover, the BOEM has the right to issue liability orders in the future, including if it determines there is a substantial risk of nonperformance of the current interest holder’s decommissioning liabilities and the Biden Administration may elect to pursue more stringent supplemental bonding requirements. Additionally, in August 2021, the BOEM published a Note to Stakeholders detailing an expansion of its supplemental financial assurance requirements currently applicable to all sole liability properties and now to certain high-risk, non-sole liability properties; namely, those properties that are inactive, where production end-of-life is fewer than five years, or with damaged infrastructure irrespective of the remaining property life of the surrounding producing assets. BOEM has stated it will prioritize non-sole liability properties where it believes that the current owner does not meet applicable financial strength and has no co-owners or predecessors that are financially strong, as determined by BOEM.

Deepwater Operations — We have interests in Deepwater fields in the U.S. Gulf of Mexico. Operations in Deepwater can result in increased operational risks as has been demonstrated by the Deepwater Horizon disaster in 2010. Despite technological advances since this disaster, liabilities for environmental losses, personal injury and loss of life and significant regulatory fines in the event of a disaster could be well in excess of insured amounts and result in significant current losses on our statements of operations as well as going concern issues.

Oil Spill Response Plan — We maintain a Regional Oil Spill Response Plan that defines our response requirements, procedures and remediation plans in the event we have an oil spill. Oil spill response plans are generally approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. Additionally, these plans are tested and drills are conducted periodically at all levels.

Hurricanes and Tropical Storms — Since our operations are in the U.S. Gulf of Mexico, we are particularly vulnerable to the effects of hurricanes and tropical storms on production and capital projects. Significant impacts could include reductions and/or deferrals of future oil and natural gas production and revenues, increased lease operating expenses for evacuations and repairs and possible acceleration of plugging and abandonment costs.

Five-Year Offshore Oil and Gas Leasing Program Update — Under the OCSLA, as amended, the BOEM within the DOI must prepare and maintain forward-looking five-year plans—referred to by BOEM as national programs or five-year programs—to schedule proposed oil and gas lease sales on the U.S. Outer Continental Shelf. On May 11, 2022, the DOI cancelled two lease auctions in the Gulf of Mexico, Lease Sales 259 and 261 included in the 2017-2022 national program that was developed under the Obama Administration, which expired on June 30, 2022. The DOI cited "conflicting court rulings" as the primary reason for not holding the two Gulf of Mexico lease sales. As discussed above under " — Significant Developments," President Biden signed the IRA 2022 into law on August 16, 2022. The IRA 2022 reinstates Lease Sale 257 held in November 2021, and requires the DOI to both accept all valid high bids received in Lease Sale 257 and issue leases to the high bidders. We were one of the most active bidders in Lease Sale 257 and we were the high bidder on 10 blocks and awarded leases on 9 blocks. Furthermore, the DOI must hold Gulf of Mexico lease sales 259 and 261 by March 31, 2023, and September 30, 2023, respectively. To that end, in January 2023, BOEM released its final environmental impact statement for Lease Sales 259 and 261 and indicated the issuance of a final record of decision by mid-February 2023.

BOEM's development of a new five-year national program typically takes place over several years, during which successive drafts of the program are published for review and comment. At the end of the process, the Secretary of the Interior must submit the Proposed Final Program to the President and to Congress for a period of at least 60 days, after which the program may be approved by the Secretary of the Interior and may take effect with no further regulatory or legislative action.

BOEM took the first formal step in pursuit of a new five-year national program in January 2018 by releasing a Draft Proposed Program. The OCSLA and its implementing regulations call for two subsequent drafts, a Proposed Program ("PP"), which is open for public comment for a period of at least 90 days, and then a Proposed Final Program, which is submitted to Congress and the President for 60 days before implementation. These later program stages also are accompanied by publication of a draft and final Programmatic Environmental Impact Statement ("PEIS"), with a period for public comment on the draft PEIS. The PP and a draft PEIS for the 2023-2028 five-year period were published in the Federal Register on July 8, 2022, with a 90-day comment period. The public comment period has now closed, and BOEM is reviewing the comments received. The PP includes no more than ten potential lease sales in the Gulf of Mexico; however, BOEM's subsequent Proposed Final Program for 2023-2028 could reduce the number of Gulf of Mexico lease sales in the national program.

When the 2023-2028 national program will be approved and implemented remains uncertain. Congress may influence the Biden Administration's development and implementation of the five-year 2023-2028 national program by submitting public comments during formal comment periods, by evaluating programs in committee oversight hearings, and, more directly, by enacting legislation with program requirements. It is possible that the program could be delayed if opponents of offshore oil and gas production initiate lawsuits challenging BOEM's actions.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;
- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- lease operating expenses;
- capital expenditures; and
- Adjusted EBITDA, which is discussed under "—Supplemental Non-GAAP Measure" below.

Basis of Presentation

Sources of Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs, that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives, which are reported in "Price risk management activities income (expense)" on our Consolidated Statements of Operations. The following table presents a breakout of each revenue component:

	Year Ended December 31,		
	2022	2021	2020
Oil	83%	86%	88%
Natural gas	14%	10%	9%
NGL	4%	4%	3%

Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Realized Prices on the Sale of Oil, Natural Gas and NGLs — The NYMEX WTI prompt month oil settlement price is a widely used benchmark in the pricing of domestic oil in the United States. The actual prices we realize from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the Gulf of Mexico Basin's proximity to U.S. Gulf Coast refineries and the quality of the oil production sold in Eugene Island Crude, Louisiana Light Sweet Crude and Heavy Louisiana Sweet Crude markets.

The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices we realize from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. Currently, the sales points of our gas production are generally within close proximity to the Henry Hub which creates a minimal differential in the prices we receive for our production versus average Henry Hub prices.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue, as indicated in the table below, which provides the high, low and average prices for NYMEX WTI and NYMEX Henry Hub monthly contract prices as well as our average realized oil, natural gas, and NGL sales prices for the periods indicated.

	Year Ended December 31,		
	2022	2021	2020
Oil:			
NYMEX WTI high per Bbl	$ 114.84	$ 81.48	$ 57.52
NYMEX WTI low per Bbl	$ 76.44	$ 52.01	$ 16.55
Average NYMEX WTI per Bbl	$ 94.79	$ 67.99	$ 39.16
Average oil sales price per Bbl (including commodity derivatives)	$ 68.40	$ 49.67	$ 47.36
Average oil sales price per Bbl (excluding commodity derivatives)	$ 93.75	$ 65.86	$ 37.09
Natural Gas:			
NYMEX Henry Hub high per MMBtu	$ 8.81	$ 5.51	$ 2.61
NYMEX Henry Hub low per MMBtu	$ 4.38	$ 2.62	$ 1.63
Average NYMEX Henry Hub per MMBtu	$ 6.42	$ 3.91	$ 2.03
Average natural gas sales price per Mcf (including commodity derivatives)	$ 5.30	$ 3.11	$ 2.00
Average natural gas sales price per Mcf (excluding commodity derivatives)	$ 7.06	$ 3.98	$ 1.87
NGLs:			
NGL realized price as a % of average NYMEX WTI	35%	39%	25%

To achieve more predictable cash flow, and to reduce exposure to adverse fluctuations in commodity prices, we enter into commodity derivative arrangements for a portion of our anticipated production. By removing a significant portion of price volatility associated with our anticipated production, we believe it will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, our price risk management activity may also reduce our ability to benefit from increases in prices. We will sustain losses to the extent our commodity derivatives contract prices are lower than market prices and, conversely, we will sustain gains to the extent our commodity derivatives contract prices are higher than market prices.

We will continue to use commodity derivative instruments to manage commodity price risk in the future. Our hedging strategy and future hedging transactions will be determined in accordance with both our Bank Credit Facility and Hedging Policy and may be different from what we have done on a historical basis.

Expenses

Lease Operating Expense — Lease operating expense consists of the daily costs incurred to bring oil, natural gas and NGLs out of the underground formation and to the market, together with the daily costs incurred to maintain our producing properties. Expenses for direct labor, insurance, a portion of the HP-I lease, materials and supplies, rental and third party costs comprise the most significant portion of our lease operating expense. It further consists of costs associated with major remedial operations on completed wells to restore, maintain or improve the well's production. Because the amount of workover and maintenance expense is closely correlated to the levels of workover activity, which is not regularly scheduled, workover and maintenance expense is not necessarily comparable from period-to-period. There is a reduction in our lease operating expenses for production handling fees related to certain reimbursements for costs from certain third parties.

Production Taxes — Production taxes consist of severance taxes levied by the Louisiana Department of Revenue on production of oil and natural gas from land or water bottoms within the boundaries of the state of Louisiana.

Depreciation, Depletion and Amortization expense — Depreciation, depletion and amortization expense is the expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas reserves. We use the full cost method of accounting for oil and natural gas activities. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies* for further discussion.

Accretion Expense — We have obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We have obligations to plug wells when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue a liability with respect to these obligations based on our estimate of the timing and amount to replace, remove or retire the associated assets. Accretion of the liability is recognized for changes in the value of the liability as a result of the passage of time over the estimated productive life of the related assets as the discounted liabilities are accreted to their expected settlement values.

General and Administrative Expense — General and administrative expense generally consists of costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production operations, bad debt expense, equity-based compensation expense, audit and other fees for professional services and legal compliance.

Interest Expense — We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Bank Credit Facility and term-based debt. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. Interest includes interest incurred under our debt agreements, the amortization of deferred financing costs (including origination and amendment fees), commitment fees, imputed interest on our capital lease, performance bond premiums and annual agency fees. Interest expense is net of capitalized interest on expenditures made in connection with exploratory projects that are not subject to current amortization.

Price Risk Management Activities — We utilize commodity derivative instruments to reduce our exposure to fluctuations in the price of oil and natural gas. We recognize gains and losses associated with our open commodity derivative contracts as commodity prices and the associated fair value of our commodity derivative contracts change. The commodity derivative contracts we have in place are not designated as hedges for accounting purposes. Consequently, these commodity derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

Results of Operations

Revenues

The information below provides a discussion of, and an analysis of significant variance in, our oil, natural gas and NGL revenues, production volumes and sales prices (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021	Change
Revenues:			
Oil	$ 1,365,148	$ 1,064,161	$ 300,987
Natural gas	227,306	130,616	96,690
NGL	59,526	49,763	9,763
Total revenues	$ 1,651,980	$ 1,244,540	$ 407,440
Total Production Volumes:			
Oil (MBbls)	14,561	16,159	(1,598)
Natural gas (MMcf)	32,215	32,795	(580)
NGL (MBbls)	1,793	1,875	(82)
Total production volume (MBoe)	21,723	23,500	(1,777)
Daily Production Volumes by Product:			
Oil (MBblpd)	39.9	44.3	(4.4)
Natural gas (MMcfpd)	88.3	89.8	(1.5)
NGL (MBblpd)	4.9	5.1	(0.2)
Total production volume (MBoepd)	59.5	64.4	(4.9)
Average Sale Price per Unit:			
Oil (per Bbl)	$ 93.75	$ 65.86	$ 27.89
Natural gas (per Mcf)	$ 7.06	$ 3.98	$ 3.08
NGL (per Bbl)	$ 33.20	$ 26.54	$ 6.66
Price per Boe	$ 76.05	$ 52.96	$ 23.09
Price per Boe (including realized commodity derivatives)	$ 56.46	$ 40.61	$ 15.85

The information below provides an analysis of the change in our oil, natural gas and NGL revenues, due to changes in sales prices and production volumes (in thousands):

	Price	Volume	Total
Revenues:			
Oil	$ 406,231	$ (105,244)	$ 300,987
Natural gas	98,998	(2,308)	96,690
NGL	11,939	(2,176)	9,763
Total revenues	$ 517,168	$ (109,728)	$ 407,440

Volumetric Analysis — Production volumes decreased by 4.9 MBoepd to 59.5 MBoepd for the year ended December 31, 2022. The decrease in production volumes was primarily due to the third party downtime for the HP-I dry-dock in our Phoenix Field, the Eugene Island Pipeline System shut-in primarily impacting HP-I and Green Canyon 18 Field and the Shell Odyssey Pipeline shut-in primarily impacting our Ram Powell Field, Main Pass 288 Field and non-operated Delta House facility, which resulted in 3.5 MBoepd of deferred production. Additionally, production volumes decreased 2.0 MBoepd and 1.2 MBoepd primarily attributable to well performance and natural production declines in our Phoenix Field and Green Canyon 18 Field, respectively. Production volumes decreased 1.4 MBoepd at Delta House, a non-operated facility located in Mississippi Canyon, primarily related to temporary shut-ins for repairs and maintenance and natural production declines. The decrease was partially offset by an increase of 4.2 MBoepd in deferred production attributable to Hurricane Ida in 2021.

Operating Expenses

Lease Operating Expense

The following table highlights lease operating expense items in total and on a cost per Boe production basis. The information below provides the financial results and an analysis of significant variances in these results (in thousands, except per Boe data):

	Year Ended December 31,	
	2022	2021
Lease operating expenses	$ 308,092	$ 283,601
Lease operating expenses per Boe	$ 14.18	$ 12.07

Total lease operating expenses for the year ended December 31, 2022 increased by approximately $24.5 million, or 9%. The increase is primarily due to a $19.7 million increase in facility and workover expense related to repairs and maintenance at the Phoenix Field and the Gunflint Field. Additionally, there was a $4.3 million increase in company and contract labor compared to the same period in 2021. On a per unit basis, lease operating expense increased $2.11 per Boe to $14.18 per Boe primarily due to decreased production of 4.9 MBoepd.

Depreciation, Depletion and Amortization

The following table highlights depreciation, depletion and amortization items in total and on a cost per Boe production basis. The information below provides the financial results and an analysis of significant variances in these results (in thousands, except per Boe data):

	Year Ended December 31,	
	2022	2021
Depreciation, depletion and amortization	$ 414,630	$ 395,994
Depreciation, depletion and amortization per Boe	$ 19.09	$ 16.85

Depreciation, depletion and amortization expense for the year ended December 31, 2022 increased by approximately $18.6 million, or 5%. This increase was primarily due to an increase of $2.25 per Boe, or 13% in the depletion rate on our proved oil and natural gas properties due to an increase in proved properties primarily related to the extension of the HP-I lease and a decline in proved reserve volumes when compared to the same period in 2021. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 5 — *Leases* for additional information on the HP-I lease extension.

General and Administrative Expense

The following table highlights general and administrative expense items in total. The information below provides the financial results and an analysis of significant variances in these results (in thousands, except per Boe data):

	Year Ended December 31,	
	2022	2021
General and administrative expense	$ 99,754	$ 78,677

General and administrative expense for the year ended December 31, 2022, increased by approximately $21.1 million, or 27%. This increase was due to transaction costs of $11.1 million primarily related to the EnVen Acquisition and $8.6 million in expenses incurred by our emerging CCS operating segment during the year ended December 31, 2022. Additionally, there was an increase of $5.1 million in employee and contract labor costs when compared to the same period in 2021. General and administrative expense includes non-cash equity-based compensation of $16.0 million during the year ended December 31, 2022, which is an increase of $5.2 million. On a per unit basis, general and administrative expense related to our Upstream operating segment increased $0.97 per Boe primarily due to decreased production of 4.9 MBoepd.

Miscellaneous

The following table highlights miscellaneous items in total. The information below provides the financial results and an analysis of significant variances in these results (in thousands):

	Year Ended December 31,	
	2022	2021
Write-down of oil and natural gas properties	$ —	$ 18,123
Accretion expense	$ 55,995	$ 58,129
Other operating expense	$ 33,902	$ 32,037
Interest expense	$ 125,498	$ 133,138
Price risk management activities expense	$ 272,191	$ 419,077
Equity method investment income	$ 14,222	$ —
Other (income) expense	$ (31,800)	$ 6,988
Income tax (benefit) expense	$ 2,537	$ (1,635)

Write-Down of Oil and Natural Gas Properties **—** Due to our non-consent to the Block 31 appraisal program, we recorded an impairment of $18.1 million for our unproved property investment in Block 31 during the year ended December 31, 2021 as the costs were not recoverable. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 4 — *Property, Plant and Equipment*.

Other Operating Expense — During the year ended December 31, 2022, we recorded $31.6 million of estimated decommissioning obligations primarily as a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. During the year ended December 31, 2021, we recorded $21.1 million of estimated decommissioning obligations. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies*.

Additionally, we recorded an impairment of $5.6 million related to the adjustment of other well equipment inventory to net realizable value, which was expensed and reflected in "Other operating (income) expense" on the Consolidated Statements of Operations during the year ended December 31, 2021. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies*.

Interest Expense — During the year ended December 31, 2022, we recorded $125.5 million of interest expense compared to $133.1 million during the year ended December 31, 2021. The change is primarily a result of the interest associated with the Bank Credit Facility with no outstanding borrowings as of December 31, 2022 when compared to $375.0 million as of December 31, 2021. See further discussion in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

Price Risk Management Activities **—** Price risk management activities for year ended December 31, 2022 resulted in a decrease of approximately $146.9 million, or 35%. The expense of $272.2 million for the year ended December 31, 2022 consisted of $425.6 million in cash settlement losses offset by $153.4 million in non-cash gains from the increase in the fair value of our open derivative contracts. The expense of $419.1 million for the year ended December 31, 2021 consisted of $290.2 million in cash settlement losses and $128.9 million in non-cash losses from the decrease in the fair value of our open derivative contracts.

These unrealized gains and losses on open derivative contracts relate to production for future periods; however, changes in the fair value of all of our open derivative contracts are recorded as a gain or loss on our Consolidated Statements of Operations at the end of each month. As a result of the derivative contracts we have on our anticipated production volumes through December 2024, we expect these activities to continue to impact net income (loss) based on fluctuations in market prices for oil and natural gas. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments* for additional information.

Equity Method Investment Income — During the year ended December 31, 2022, we recorded a $15.3 million gain on partial sale of our equity method investment in Bayou Bend offset by equity losses of $1.1 million. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Related Party Transactions* for additional information.

Other (Income) Expense — During the year ended December 31, 2022, we recorded a $27.5 million gain as a result of the settlement agreement to resolve a previously pending litigation that was filed in October 2017 that is further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies*. This was partially offset by a $1.6 million loss on extinguishment of debt as a result of the redemption of the 12.00% Notes further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

During the year ended December 31, 2021, we recorded a $13.2 million loss on extinguishment of debt as a result of the redemption of the 11.00% Notes further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*. This was partially offset by a $4.4 million gain as a result of the settlement related to the Whistler Acquisition that is further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Related Party Transactions*.

Income Tax Benefit (Expense) — During the year ended December 31, 2022, we recorded $2.5 million of income tax expense compared to $1.6 million of income tax benefit during the year ended December 31, 2021, primarily a result of non-deductible losses in the U.S. and recognition of a valuation allowance for our excess federal and state deferred tax assets in the year ended December 31, 2022. The realization of our deferred tax asset depends on recognition of sufficient future taxable income in specific tax jurisdictions in which temporary differences or net operating losses relate. In assessing the need for a valuation allowance, we consider whether it is more likely than not that some portion of all of the deferred tax assets will not be realized. See additional information on the valuation allowance as described in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 9 — *Income Taxes*.

Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies*. Additionally, we are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuit with certainty, but our management believes it is remote that any such pending or threatened lawsuit will have a material adverse impact on our financial condition. See Part I, Item 3. Legal Proceedings for additional information.

Due to the nature of our business, we are, from time-to-time, involved in other routine litigation or subject to disputes or claims related to business activities, including workers' compensation claims, employment related disputes and civil penalties by regulators. In the opinion of our management, none of these other pending litigations, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations. See Part I, Item 3. Legal Proceedings for additional information.

Supplemental Non-GAAP Measure

EBITDA and Adjusted EBITDA

"EBITDA" and "Adjusted EBITDA" are non-GAAP financial measures used to provide management and investors with (i) additional information to evaluate, with certain adjustments, items required or permitted in calculating covenant compliance under our debt agreements, (ii) important supplemental indicators of the operational performance of our business, (iii) additional criteria for evaluating our performance relative to our peers and (iv) supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDA and Adjusted EBITDA have limitations as analytical tools and should not be considered in isolation or as substitutes for analysis of our results as reported under GAAP or as alternatives to net income (loss), operating income (loss) or any other measure of financial performance presented in accordance with GAAP.

We define these as the following:

- ***EBITDA —*** Net income (loss) plus interest expense, income tax expense (benefit), depreciation, depletion and amortization, and accretion expense.
- ***Adjusted EBITDA —*** EBITDA plus non-cash write-down of oil and natural gas properties, transaction and other (income) expenses, decommissioning obligations, the net change in the fair value of derivatives (mark to market effect, net of cash settlements and premiums related to these derivatives), (gain) loss on debt extinguishment, non-cash write-down of other well equipment inventory and non-cash equity-based compensation expense.

The following table presents a reconciliation of the GAAP financial measure of net income (loss) to Adjusted EBITDA for each of the periods indicated (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 381,915	$ (182,952)	$ (465,605)
Interest expense	125,498	133,138	99,415
Income tax expense (benefit)	2,537	(1,635)	35,583
Depreciation, depletion and amortization	414,630	395,994	364,346
Accretion expense	55,995	58,129	49,741
EBITDA	980,575	402,674	83,480
Write-down of oil and natural gas properties	—	18,123	267,916
Transaction and other (income) expense[1]	(34,513)	5,886	14,917
Decommissioning obligations[2]	31,558	21,055	—
Derivative fair value (gain) loss[3]	272,191	419,077	(87,685)
Net cash received (paid) on settled derivative instruments[3]	(425,559)	(290,164)	143,905
(Gain) loss on debt extinguishment	1,569	13,225	(1,662)
Non-cash write-down of other well equipment inventory	—	5,606	699
Non-cash equity-based compensation expense	15,953	10,992	8,669
Adjusted EBITDA	$ 841,774	$ 606,474	$ 430,239

(1) Other income (expense) includes restructuring expenses, cost saving initiatives and other miscellaneous income and expenses that we do not view as a meaningful indicator of our operating performance. For the year ended December 31, 2022, the amount includes $27.5 million gain as a result of the settlement agreement to resolve previously pending litigation that was filed in October 2017 that is further discussed in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies.* Additionally, it includes a $15.3 million gain for the year ended December 31, 2022 on partial sale of our investment in Bayou Bend that is further discussed Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Related Party Transactions*. For the year ended December 31, 2020, the amount includes $1.4 million of legal entity restructuring costs and $1.3 million of severance related cost saving initiatives due to the COVID-19 pandemic.

(2) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies* for additional information on decommissioning obligations.

(3) The adjustments for the derivative fair value (gains) losses and net cash receipts (payments) on settled commodity derivative instruments have the effect of adjusting net loss for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDA on an unrealized basis during the period the derivatives settled.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our Bank Credit Facility. Our primary uses of cash are for capital expenditures, working capital, debt service and for general corporate purposes. Our working capital deficit has decreased since December 31, 2021 primarily due to a decrease of $118.2 million in liabilities from price risk management activities and an increase of $24.1 million in assets from price risk management activities. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments* for additional information. As of December 31, 2022, our available liquidity (cash plus available capacity under the Bank Credit Facility) was $846.5 million.

We fund exploration and development activities primarily through operating cash flows, cash on hand and through borrowings under the Bank Credit Facility, if necessary. Historically, we have funded significant property acquisitions with the issuance of senior notes, borrowings under the Bank Credit Facility and through additional equity issuances. We occasionally adjust our capital budget in response to changing operating cash flow forecasts and market conditions, including the prices of oil, natural gas and NGLs, acquisition opportunities and the results of our exploration and development activities.

Capital Expenditures — The following is a table of our capital expenditures, excluding acquisitions, for the year ended December 31, 2022 (in thousands):

U.S. drilling & completions	$	234,173
Mexico appraisal & exploration		372
Asset management[(1)]		102,027
Seismic and G&G, land, capitalized G&A and other		44,881
CCS[(2)]		2,778
Total capital expenditures		384,231
Plugging & abandonment		69,596
Decommissioning obligations settled[(3)]		1,625
Total	$	455,452

(1) Asset management consists of capital expenditures for development-related activities primarily associated with recompletions and improvements to our facilities and infrastructure.

(2) Excludes $2.7 million of expenditures reflected as "Other operating (income) expense" on the Consolidated Statements of Operations.

(3) Settlement of decommissioning obligations as a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies* for additional information on decommissioning obligations.

Based on our current level of legacy operations, the recently acquired EnVen operations, and available cash, we believe our cash flows from operations, combined with availability under the Bank Credit Facility, provide sufficient liquidity to fund our board approved 2023 Upstream capital spending program of $650.0 million to $675.0 million as well as expected investments in our CCS operating segment of $70.0 million to $90.0 million. However, our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the Bank Credit Facility, and (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, depends on operating and economic conditions, some of which are beyond our control. To the extent possible, we have attempted to mitigate certain of these risks (e.g. by entering into oil and natural gas derivative contracts to reduce the financial impact of downward commodity price movements on a substantial portion of our anticipated production), but we could be required to, or we or our affiliates may from time to time, take additional future actions on an opportunistic basis. To address further changes in the financial and/or commodity markets, future actions may include, without limitation, issuing debt, including secured debt, or issuing equity to directly or independently repurchase or refinance our outstanding indebtedness.

Overview of Cash Flow Activities — The following table summarizes cash flows provided by (used in) by type of activity, for the following periods (in thousands):

	Year Ended December 31,			
	2022		2021	
Operating activities	$	709,739	$	411,388
Investing activities	$	(311,977)	$	(293,747)
Financing activities	$	(423,469)	$	(82,022)

Operating Activities — Net cash provided by operating activities increased $298.4 million in 2022 compared to 2021 primarily attributable to an increase in revenues net of lease operating expense of $382.9 million. This was offset by an increase in cash payments on derivatives of $135.4 million.

Investing Activities — Net Cash used in investing activities increased $18.2 million in 2022 compared to 2021 primarily due to an increase in capital expenditures of $29.8 million offset by proceeds of $15.0 million from a partial sale of our investment in Bayou Bend. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 11 — *Related Party Transactions* for additional information.

Financing Activities — Net cash used in financing activities increased $341.4 million in 2022 compared to 2021. During the year ended December 31, 2022, net repayments of $375.0 million reduced the Bank Credit Facility. Additionally, we redeemed $12.1 million and $6.1 million of our 12.00% Notes and 7.50% Senior Notes (as defined herein), respectively.

During the year ended December 31, 2021, the issuance of the 12.00% Notes in January 2021 generated $579.0 million after original discount and deferred financing costs. The net proceeds from the 12.00% Notes funded the $356.8 million redemption of the 11.00% Notes and reduced the indebtedness under the Bank Credit Facility by $175.0 million in the first quarter of 2021. Indebtedness under the Bank Credit Facility was then further reduced by $90.0 million during the remainder of 2021.

Overview of Debt Instruments

Financing Arrangements — As of December 31, 2022, total debt, net of discount and deferred financing costs, was approximately $585.3 million, comprised of our $638.5 million aggregate principal amount of the 12.00% Notes and no outstanding borrowings under our Bank Credit Facility. We were in compliance with all debt covenants at December 31, 2022. For additional details on our debt, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

Bank Credit Facility – matures March 2027 — We maintain a Bank Credit Facility with a syndicate of financial institutions. The Bank Credit Facility provides for determination of the borrowing base based on our proved producing reserves and a portion of our proved undeveloped reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter each year. For additional details on our Bank Credit Facility, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

12.00% Second-Priority Senior Secured Notes—due January 2026 — The 12.00% Notes were issued pursuant to an indenture dated January 4, 2021 and the first supplemental indenture dated January 14, 2021 between Talos Energy Inc. (the "Parent Guarantor"); Talos Production Inc. (the "Issuer"); the Subsidiary Guarantors (defined below); and Wilmington Trust, National Association, as trustee and collateral agent. The 12.00% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indentures. The 12.00% Notes are secured on a second-priority senior secured basis by liens on substantially the same collateral as the Issuer's existing first-priority obligations under its Bank Credit Facility. The 12.00% Notes mature on January 15, 2026 and have interest payable semi-annually each January 15 and July 15. We made an interest payment of $38.7 million on January 17, 2023. For additional details on the 12.00% Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

Redemption of the 11.00% Second-Priority Senior Secured Notes—due April 2022 — On January 13, 2021, we redeemed the 11.00% Notes using the proceeds from the issuance of the 12.00% Notes. For additional details on this redemption, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

7.50% Senior Notes – redeemed May 2022 — The 7.50% Senior Notes due 2022 ("7.50% Senior Notes") matured and were redeemed on May 31, 2022. For additional details on the 7.50% Senior Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

EnVen's 11.75% Senior Secured Second Lien Notes—due April 2026 — On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the Company assumed EnVen's 11.75% Senior Secured Second Lien Notes due 2026 (the "EnVen Second Lien Notes") with a principal amount of $257.5 million. The EnVen Second Lien Notes will mature on April 15, 2026 and interest accrues and is to be paid semi-annually in cash in arrears on April 15^{th} and October 15^{th} of each year. The indenture governing the EnVen Second Lien Notes requires the redemption of $15.0 million of the principal amount outstanding at par value on April 15^{th} and October 15^{th} of each year. For additional details on the EnVen Second Lien Notes, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*.

Guarantor Financial Information — We own no operating assets and have no operations independent of our subsidiaries. The 12.00% Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by the Parent Guarantor and on a second-priority senior secured basis by each of the Issuer's present and future direct or indirect wholly owned material restricted subsidiaries that guarantees the Issuer's senior reserve-based revolving credit facility (collectively, the "Subsidiary Guarantors" and, together with the Parent Guarantor, the "Guarantors"). Our non-domestic subsidiaries (other than Talos International Holdings SCS) and our unrestricted CCS domestic subsidiaries (the "Non-Guarantors") are 100% owned by us but do not guarantee the 12.00% Notes.

In lieu of providing separate financial statements for the Issuer and the Guarantors, we have presented the accompanying supplemental summarized combined balance sheet and statement of operations information for the Issuer and the Guarantors on a combined basis after elimination of intercompany transactions and amounts related to investment in any subsidiary that is a Non-Guarantor**.**

The following table presents the balance sheet information for the respective periods (in thousands):

	Year Ended December 31,	
	2022	2021
Current assets	$ 344,525	$ 330,415
Non-current assets	2,571,254	2,305,855
Total assets	$ 2,915,779	$ 2,636,270
Current liabilities	$ 599,669	$ 598,062
Non-current liabilities	1,285,992	1,405,382
Talos Energy Inc. stockholders' equity	1,030,118	632,826
Total liabilities and stockholders' equity	$ 2,915,779	$ 2,636,270

The following table presents the income statement information (in thousands):

	Year Ended December 31, 2022
Revenues	$ 1,651,980
Costs and expenses	(1,271,834)
Net income	$ 380,146

***Material Cash Requirements* —** We are party to various contractual obligations. Some of these obligations may be reflected in our accompanying Consolidated Financial Statements, while other obligations, such as certain operating leases and capital commitments, are not reflected on our accompanying Consolidated Financial Statements.

The following table and discussion summarizes our material cash requirements from known contractual obligations as of December 31, 2022 (in thousands):

	2023	2024	2025	2026	2027	Thereafter	Total[4]
Long-term financing obligations:							
Debt principal	$ —	$ —	$ —	$ 638,541	$ —	$ —	$ 638,541
Debt interest	80,769	80,274	76,625	3,193	—	—	240,861
Vessel commitments[1]	41,938	—	—	—	—	—	41,938
Derivative liabilities	68,370	7,872	—	—	—	—	76,242
Operating lease obligations	3,774	3,579	3,645	3,712	3,596	5,727	24,033
Finance lease[2]	46,407	19,336	—	—	—	—	65,743
Purchase obligations[3]	41,148	—	—	—	—	—	41,148
EnVen Acquisition[4]	259,858	—	—	—	—	—	259,858
Other commitments[5]	9,627	327	327	—	—	—	10,281
Total contractual obligations[6]	$ 551,891	$ 111,388	$ 80,597	$ 645,446	$ 3,596	$ 5,727	$1,398,645

(1) Includes vessel commitments we will utilize for certain Deepwater well intervention, drilling operations and decommissioning activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by us will be billed for their working interest share of such costs.

(2) Lease agreement for the HP-I floating production facility in the Phoenix Field.

(3) Includes committed purchase orders to execute planned future drilling activities.

(4) Includes cash consideration and contingent fees related to the EnVen Acquisition. See Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 15 — *Subsequent Events* for further information on the EnVen Acquisition.

(5) Includes commitment to acquire additional lease acreage associated with our CCS Segment.

(6) This table does not include our estimated discounted liability for dismantlement, abandonment and restoration costs of oil and natural gas properties of $541.7 million as of December 31, 2022. For additional information regarding these liabilities, please see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 4 — *Property, Plant and Equipment*. Additionally, this table does not include liabilities associated with our decommissioning obligations. For additional information regarding our decommissioning obligations, please see please see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitment and Contingencies*.

On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the Company assumed contractual obligations that have material cash requirements. Examples of those contractual obligations include, but are not limited to:

- The EnVen Second Lien Notes as discussed above;
- Derivative liabilities;
- Seismic data licensing change of control payments; and
- EnVen's leased office space located in Downtown Houston.

Performance Obligations — As of December 31, 2022, we had secured performance bonds totaling $740.6 million primarily related to plugging and abandonment of wells and removal of facilities in the U.S. Gulf of Mexico and certain obligations under the PSCs with Mexico from third party sureties. Additionally, we had secured letters of credit issued under our Bank Credit Facility totaling $3.9 million. Letters of credit that are outstanding reduce the available revolving credit commitments.

For additional information about certain of our obligations and contingencies, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 12 — *Commitments and Contingencies*.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense, and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those estimates that require complex or subjective judgment in the application of the accounting policy and that could significantly impact our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Our management has identified the following critical accounting estimates. Our significant accounting policies are described in Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 2 — *Summary of Significant Accounting Policies*.

Oil and Natural Gas Properties — The Company follows the full cost method of accounting for oil and natural gas exploration and development activities. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, dry hole costs and geological and geophysical costs are capitalized into the Full Cost Pool, which is subject to amortization and assessed for impairment on a quarterly basis through a ceiling test calculation as discussed below.

Capitalized costs associated with proved reserves are amortized on a country-by-country basis over the life of the total proved reserves using the unit of production method, computed quarterly. Conversely, capitalized costs associated with unproved properties and related geological and geophysical costs, exploration wells currently drilling and capitalized interest are initially excluded from the amortizable base. The Company transfers unproved property costs into the amortizable base when properties are determined to have proved reserves or when the Company has completed an unproved properties evaluation resulting in an impairment. The Company evaluates each of these unproved properties individually for impairment at least quarterly. Additionally, the amortizable base includes future development costs, dismantlement, restoration and abandonment costs, net of estimated salvage values, and geological and geophysical costs incurred that cannot be associated with specific unproved properties or prospects in which the Company owns a direct interest. The Company capitalizes overhead costs that are directly related to exploration, acquisition and development activities.

The Company's capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Any costs in excess of the ceiling for U.S. oil and gas properties are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on the Company's Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. The Company performs this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, the Company utilizes SEC Pricing when performing the ceiling test. The Company also holds prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period.

Under the full cost method of accounting for oil and natural gas operations, assets whose costs are currently being depreciated, depleted or amortized are assets in use in the earnings activities of the enterprise and do not qualify for capitalization of interest cost. Investments in unproved properties for which exploration and development activities are in progress and other major development projects that are not being currently depreciated, depleted or amortized are assets qualifying for capitalization of interest costs.

When the Company sells or conveys interests in oil and natural gas properties, the Company reduces its oil and natural gas reserves for the amount attributable to the sold or conveyed interest. The Company treats sales proceeds on non-significant sales as reductions to the cost of the Company's oil and natural gas properties. The Company does not recognize a gain or loss on sales of oil and natural gas properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves.

Proved Reserve Estimates — We estimate our proved oil, natural gas and NGL reserves in accordance with the guidelines established by the SEC. Proved oil, natural gas and NGL reserves are those quantities of oil, natural gas and NGLs, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future periods from known reservoirs and under existing economic conditions, operating methods and governmental regulations. Prices are determined using SEC pricing.

Our estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. The estimates of proved reserves are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions and governmental restrictions. Decreases in price, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date. A material adverse change in the estimated volumes of proved reserves could have a negative impact on depreciation, depletion and amortization or could result in property impairments.

Fair Value Measure of Financial Instruments — Our financial instruments generally consisted of cash and cash equivalents, accounts receivable, commodity derivatives, accounts payable and debt as of December 31, 2022. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments.

Fair value accounting standards define fair value, establish a consistent framework for measuring fair value and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify fair value as an exit price, presenting the amount that would be received to sell an asset or paid to transfer a liability, in an orderly transaction between market participants. We follow a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

- ***Level 1 —*** Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- ***Level 2 —*** Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement.
- ***Level 3 —*** Inputs to the valuation methodology are unobservable (little or no market data), which require us to develop our own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

- ***Market Approach —*** Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
- ***Cost Approach —*** Amount that would be required to replace the service capacity of an asset (replacement cost).
- ***Income Approach —*** Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Asset Retirement Obligations — The Company has obligations associated with the retirement of its oil and natural gas wells and related infrastructure. The Company has obligations to plug wells when production on those wells is exhausted, when the Company no longer plans to use them or when the Company abandons them. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Changes in estimate in the table below represent changes to the expected amount and timing of payments to settle its asset retirement obligations. Typically, these changes result from obtaining new information about the timing of its obligations to plug and abandon oil and natural gas wells and the costs to do so. After initial recording, the liability is increased for the passage of time, with the increase being reflected as “Accretion expense” on the Company’s Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for asset retirement obligations, the Company recognizes the difference as an adjustment to proved properties.

Revenue Recognition and Imbalances — Revenues are recorded based from the sale of oil, natural gas and NGLs based on quantities of production sold to purchasers under short-term contracts (less than twelve months) at market prices when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or when a barge lifting has occurred.

Revenues are recorded based on the actual sales volumes sold to purchasers. An imbalance receivable or payable is recorded only to the extent the imbalance is in excess of its share of remaining proved developed reserves in an underlying property. Our imbalances are presented gross on our Consolidated Balance Sheets. At December 31, 2022 and 2021, our imbalance receivable was approximately \$1.7 million and \$1.7 million, respectively, and imbalance payable was approximately \$2.5 million and \$2.5 million, respectively.

Income Taxes — Our provision for income taxes includes U.S. state and federal and foreign taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. As of December 31, 2022, we believe it is more likely than not that some or all of the benefits from our federal and state deferred tax assets will not be realized and reduced the net federal and state deferred tax assets by a valuation allowance. We maintain a valuation allowance on most of our Mexico deferred tax assets.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recently Adopted Accounting Standards

None.

Recently Issued Accounting Standards

There were no recently issued accounting standards material to us.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are currently exposed to market risk in two areas: commodity prices and, to a lesser extent, interest rate risk. Our risk management activities involve the use of derivative financial instruments to mitigate the impact of market price risk exposures primarily related to our oil and natural gas production.

We are subject to a minimum hedging requirement under our Bank Credit Facility for each calendar month on a six-full fiscal quarter rolling basis. For any quarter occurring during the first four forward fiscal quarters, we are required to hedge a minimum of 50% of our reasonably anticipated projected production from proved developed producing reserves from the semi-annual reserves report delivered to the administrative agent of our Bank Credit Facility, adjusted to 45% in July and November and 25% in August, September and October. For the fifth and sixth forward fiscal quarters, if the Consolidated Total Debt to EBITDAX Ratio (as defined in the Bank Credit Facility) is greater than or equal to 1.00 to 1.00, then we are required to hedge a minimum of 25%, adjusted to 20% in August, September and October.

All derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded as “Price risk management activities income (expense)” on the Consolidated Statements of Operations in each period.

Commodity Price Risks

Oil and natural gas prices can fluctuate significantly and have a direct impact on our revenues, earnings and cash flow. During year ended December 31, 2022, our average oil price realizations after the effect of derivatives increased 38% to $68.40 per Bbl from $49.67 per Bbl in the comparable 2021 period. Our average natural gas price realizations after the effect of derivatives increased 70% during the year ended December 31, 2022 to $5.30 per Mcf from $3.11 per Mcf in the comparable 2021 period.

Price Risk Management Activities

We have attempted to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of oil and natural gas swaps. These contracts will impact our earnings as the fair value of these derivatives changes. Our derivatives will not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we will be subject to commodity price risks on our remaining forecasted production.

We had commodity derivative instruments in place to reduce the price risk associated with future production of 9,537 MBbls of crude oil and 18,764 MMBtu of natural gas at December 31, 2022, with a net derivative liability position of $43.4 million. For additional information regarding our commodity derivative instruments, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 6 — *Financial Instruments*, included elsewhere in this Annual Report. The table below presents the hypothetical sensitivity of our commodity price risk management activities to changes in fair values arising from immediate selected potential changes in oil and natural gas prices at December 31, 2022 (in thousands):

		Oil and Natural Gas Derivatives			
		Ten Percent Increase		Ten Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
Price impact[1]	$ (43,359)	$ (117,556)	$ (74,197)	$ 30,778	$ 74,137

(1) Presents the hypothetical sensitivity of our commodity price risk management activities to changes in fair values arising from changes in oil and natural gas prices.

Variable Interest Rate Risks

We had total debt outstanding of $638.5 million at December 31, 2022, before unamortized original issue discount and deferred financing costs, from our 12.00% Notes, which bears interest at a fixed rate. There were no outstanding borrowings under our Bank Credit Facility with variable interest rates. We are subject to the risk of changes in interest rates under our Bank Credit Facility. In addition, the terms of our Bank Credit Facility require us to pay higher interest rates as we utilize a larger percentage of our available borrowing base. We manage our interest rate exposure by maintaining a combination of fixed and variable rate debt and monitoring the effect of market changes in interest rates. As of December 31, 2022, our interest rate risk exposure is mitigated as a result of fixed interest rates on 100% of our debt. For additional information regarding the borrowing base utilization percentage associated with our Bank Credit Facility, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 7 — *Debt*, included elsewhere in this Annual Report.

Item 8. Financial Statements and Supplementary Data

See the Consolidated Financial Statements and Report of Independent Registered Public Accounting Firm as of December 31, 2022 and 2021 and for the years ended December 31, 2022, 2021 and 2020, included in Part IV, Item 15. Exhibits and Financial Statements Schedules.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rules 13a- 15(e) and 15d- 15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Based on such evaluation, our chief executive officer and chief financial officer have concluded that as of December 31, 2022, our disclosure controls and procedures are designed at a reasonable assurance level and are effective to provide reasonable assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of SEC, and that such information is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosures.

Management’s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Management conducted an assessment of the effectiveness of our internal control over financial reporting based on the criteria set forth in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on the assessment, management has concluded that its internal control over financial reporting was effective as of December 31, 2022 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with GAAP. Our independent registered public accounting firm, Ernst & Young LLP, has issued an audit report with respect to our internal control over financial reporting, which is included in this Annual Report.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting identified in management's evaluation pursuant to Rules 13a-15(d) or 15d-15(d) of the Exchange Act during the fourth quarter of 2022 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspection

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Our board of directors has adopted a Code of Business Conduct and Ethics applicable to all officers, directors and employees, which is available on our website (*www.talosenergy.com*) under "Corporate Governance" within the "Investors" tab. We intend to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding amendment to, or waiver from, a provision of our Code of Business Conduct and Ethics by posting such information on the website address and location specified above.

Item 11. Executive Compensation

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated by reference to our Proxy Statement for the 2023 Annual Meeting of Stockholders to be filed with the SEC within 120 days of the fiscal year ended December 31, 2022.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

(1) **Financial Statements:**

Refer to the Index to Consolidated Financial Statements on page F-1 for a list of all financial statements filed as part of this Annual Report on Form 10-K.

(2) **Financial Statement Schedules:**

Other than as stated on the Index to Consolidated Financial Statements on page F-1 with respect to Schedule I, financial statement schedules have been omitted because they are either not material, not required, not applicable or the information required to be presented is included in our Consolidated Financial Statements and related notes.

(3) **Exhibits:**

Exhibit Number	Description
2.1#	Transaction Agreement, dated as of November 21, 2017, by and among Stone Energy Corporation, Sailfish Energy Holdings Corporation, Sailfish Merger Sub Corporation, Talos Energy LLC and Talos Production LLC (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
2.2#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings, LLC (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.3	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings LLC (incorporated by reference to Exhibit 2.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.4#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings II, LLC (incorporated by reference to Exhibit 2.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.5	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings II LLC (incorporated by reference to Exhibit 2.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.6#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings III LLC (incorporated by reference to Exhibit 2.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.7	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and ILX Holdings III LLC (incorporated by reference to Exhibit 2.6 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.8#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and Castex Energy 2014, LLC (incorporated by reference to Exhibit 2.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).
2.9	Amendment to Purchase and Sale Agreement, dated as of February 24, 2020, by and among Talos Energy Inc., Talos Production Inc. and Castex Energy 2014, LLC (incorporated by reference to Exhibit 2.8 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 25, 2020).
2.10#	Purchase and Sale Agreement, dated as of December 10, 2019, by and among Talos Energy Inc., Talos Production Inc. and Castex Energy 2016, LP (incorporated by reference to Exhibit 2.5 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).

2.11#	Agreement and Plan of Merger, dated as of September 21, 2022, by and among Talos Energy Inc., Talos Production Inc., Tide Merger Sub I Inc., Tide Merger Sub II LLC, Tide Merger Sub III LLC, BCC Enven Investments, L.P. and EnVen Energy Corporation (incorporated by reference to Exhibit 2.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on September 22, 2022).
3.1	Second Amended and Restated Certificate of Incorporation of Talos Energy Inc. (incorporated by reference to Exhibit 3.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
3.2	Second Amended and Restated Bylaws of Talos Energy Inc. (incorporated by reference to Exhibit 3.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
4.1	Form of Stock Certificate for Common Stock of Talos Energy Inc. (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Amendment No. 1 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on February 9, 2018).
4.2	Indenture, dated as of January 4, 2021, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021).
4.3	First Supplemental Indenture, dated as of January 14, 2021, by and among Talos Production Inc., the Guarantors named therein and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 14, 2021).
4.4	Form of 12.00% Second-Priority Senior Secured Note due 2026 (included as Exhibit A to Exhibit 4.6 hereto) (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021).
4.5	Registration Rights Agreement, dated as of January 4, 2021, by and among Talos Production Inc., the Guarantors named therein and J.P. Morgan Securities LLC, as representative of the initial purchasers of the 2026 Notes (incorporated by reference to Exhibit 4.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 8, 2021).
4.6	Registration Rights Agreement, dated as of January 14, 2021, by and among Talos Production Inc., the Guarantors named therein and J.P. Morgan Securities LLC, as representative of the initial purchasers of the 2026 Notes (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 14, 2021).
4.7	Registration Rights Agreement, dated as of May 10, 2018, by and among Talos Energy Inc. and each of the other parties set forth on the signature pages thereto (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
4.8	Registration Rights Agreement Amendment, dated as of February 28, 2020, by and among Talos Energy Inc. and each of the other parties set forth on the signature pages thereto (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 2, 2020).
4.9	Registration Rights Agreement, dated September 21, 2022, by and among Talos Energy Inc. and the Persons listed on Schedule A thereto (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on September 22, 2022).
4.10*	Description of Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934.
4.11	Second Supplemental Indenture, dated as of October 27, 2022, among Talos Production Inc., the Guarantors named therein and Wilmington Trust National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on October 28, 2022).

4.12	Indenture, dated as of April 15, 2021, by and among Energy Ventures GoM LLC, EnVen Finance Corporation, Talos Production Inc. (as successor in interest to EnVen Energy Corporation), the other guarantors party thereto and Wilmington Trust, National Association, as trustee and as collateral agent (incorporated by reference to Exhibit 4.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
4.13	Second Supplemental Indenture, dated as of February 13, 2023, among Talos Production Inc., each of the other guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (incorporated by reference to Exhibit 4.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
4.14	Third Supplemental Indenture, dated as of February 13, 2023, among Talos Production Inc., Energy Ventures GoM LLC, EnVen Finance Corporation, each of the other guarantors party thereto and Wilmington Trust, National Association, as trustee and collateral agent (incorporated by reference to Exhibit 4.4 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
10.1	Credit Agreement, dated as of May 10, 2018, by and among Talos Production LLC, as borrower, Talos Energy Inc., as holdings, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders named therein (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K12B/A filed with the SEC on July 18, 2018).
10.2	Intercreditor Agreement, dated as of May 10, 2018, between JPMorgan Chase Bank, N.A., as First Lien Agent, and Wilmington Trust, National Association, as Second Lien Agent (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.3†	Offer Letter between Talos Energy Inc. and Shannon Young, dated as of April 13, 2019 (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on April 24, 2019).
10.4†	Offer Letter between Talos Energy Inc. and Robert D. Abendschein, dated as of December 26, 2019 (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on January 23, 2020).
10.5†	Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and Timothy S. Duncan (incorporated by reference to Exhibit 10.10 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.6†	Employment Agreement, dated as of February 3, 2012, by and between Talos Energy Operating Company LLC and John A. Parker (incorporated by reference to Exhibit 10.12 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.7†	Employment Agreement, dated as of August 30, 2013, by and between Talos Energy Operating Company LLC and William S. Moss III (incorporated by reference to Exhibit 10.14 to Talos Energy Inc.'s Amendment No. 3 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on March 30, 2018).
10.8†	Talos Energy Inc. Long Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.9†	Talos Energy Inc. 2021 Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).
10.10	Contract for the Exploration and Extraction of Hydrocarbons under Production Sharing Modality (Contract Area 7), dated as of September 4, 2015, by and among the National Hydrocarbons Commission, Sierra O&G Exploración y Producción, S. de R.L. de C.V., Talos Energy Offshore México 7, S. de R.L. de C.V. and Premier Oil Exploration and Production Mexico, S.A. de C.V. (incorporated by reference to Exhibit 10.9 to Talos Energy Inc.'s Amendment No. 4 to the Registration Statement on Form S-4 (File No. 333-222341) filed with the SEC on April 4, 2018).

10.11†	Indemnification Agreement (Timothy S. Duncan) (incorporated by reference to Exhibit 10.5 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.12†	Indemnification Agreement (Stephen E. Heitzman) (incorporated by reference to Exhibit 10.6 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.13†	Indemnification Agreement (John A. Parker) (incorporated by reference to Exhibit 10.7 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.14†	Indemnification Agreement (Michael L. Harding II) (incorporated by reference to Exhibit 10.8 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.15†	Indemnification Agreement (William S. Moss III) (incorporated by reference to Exhibit 10.9 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.16†	Indemnification Agreement (Olivia C. Wassenaar) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on November 23, 2018).
10.17†	Indemnification Agreement (Christine Hommes) (incorporated by reference to Exhibit 10.11 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.18†	Indemnification Agreement (Robert M. Tichio) (incorporated by reference to Exhibit 10.12 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.19†	Indemnification Agreement (Neal P. Goldman) (incorporated by reference to Exhibit 10.14 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.20†	Indemnification Agreement (John "Brad" Juneau) (incorporated by reference to Exhibit 10.15 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.21†	Indemnification Agreement (James M. Trimble) (incorporated by reference to Exhibit 10.16 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.22†	Indemnification Agreement (Charles M. Sledge) (incorporated by reference to Exhibit 10.17 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.23†	Indemnification Agreement (Donald R. Kendall, Jr.) (incorporated by reference to Exhibit 10.18 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.24†	Indemnification Agreement (Rajen Mahagaokar) (incorporated by reference to Exhibit 10.19 to Talos Energy Inc.'s Form 8-K12B filed with the SEC on May 16, 2018).
10.25†	Indemnification Agreement (Paula R. Glover) (incorporated by reference to Exhibit 10.27 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 25, 2022).
10.26†	Indemnification Agreement (Shannon E. Young III), effective as of May 16, 2019 (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K filed with the SEC on April 24, 2019).
10.27†	Indemnification Agreement (Robert D. Abendschein) (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K filed with the SEC on January 23, 2020).
10.28†	Indemnification Agreement (Shandell Szabo) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
10.29†	Indemnification Agreement (Richard Sherrill) (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
10.30†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Agreement (Directors) (incorporated by reference to Exhibit 10.20 to Talos Energy Inc.'s Form 10-Q filed with the SEC on August 9, 2018).
10.31†	Form of Talos Energy Inc. Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Directors) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).

10.32†	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.32 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-227362) filed with the SEC on September 14, 2018)
10.33†	Form of Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (incorporated by reference to Exhibit 10.33 to Talos Energy Inc.'s Registration Statement on Form S-4 (File No. 333-227362) filed with the SEC on September 14, 2018).
10.34†	Form of Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).
10.35†	Form of Talos Energy Inc. 2021 Long Term Incentive Plan Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (incorporated by reference to Exhibit 10.4 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 6, 2021).
10.36†	Form of Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Directors) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on November 3, 2021).
10.37†	Form of Talos Energy Inc. 2021 Long Term Incentive Plan Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement (Executives) (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 5, 2022).
10.38†	Form of Talos Energy Inc. 2021 Long Term Incentive Plan Performance Share Unit Grant Notice and Performance Share Unit Agreement (Executives) (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 5, 2022).
10.39†	Form of Performance Share Unit Cancellation and Release Agreement (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on May 5, 2022).
10.40†	Talos Energy Operating Company LLC Executive Severance Plan (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on September 5, 2018).
10.41†	Form of Participation Agreement pursuant to the Talos Energy Operating Company LLC Executive Severance Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K filed with the SEC on September 5, 2018).
10.42†	Talos Energy Operating Company LLC Amended and Restated Executive Severance Plan (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on March 2, 2020).
10.43†	Form of Participation Agreement pursuant to Talos Energy Operating Company LLC Amended and Restated Executive Severance Plan (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on October 26, 2020).
10.44	Joinder, First Amendment to Credit Agreement, and Borrowing Base Reaffirmation Agreement, dated as of July 3, 2019, by and among Talos Energy Inc., as holdings, Talos Production LLC, as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender, and the lenders (including the new lenders) party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K filed with the SEC on July 10, 2019).
10.45	Joinder, Commitment Increase Agreement, Second Amendment to Credit Agreement, Borrowing Base Redetermination Agreement, and Amendment to Other Credit Documents, dated as of December 10, 2019, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender, and the lenders (including the new lenders) party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 16, 2019).

10.46	Third Amendment to Credit Agreement and Borrowing Base Redetermination Agreement, dated as of June 19, 2020, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swing line lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on June 25, 2020).
10.47	Borrowing Base Redetermination Agreement and Sixth Amendment to Credit Agreement, dated as of June 22, 2021, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party thereto, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender and the lenders party thereto (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on June 23, 2021).
10.48	Incremental Agreement, Borrowing Base Redetermination Agreement and Seventh Amendment to Credit Agreement, dated as of December 21, 2021, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party thereto, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.45 to Talos Energy Inc.'s Form 10-K (File No. 001-38497) filed with the SEC on February 25, 2022).
10.49	Borrowing Base Redetermination Agreement and Eighth Amendment to Credit Agreement, dated as of May 4, 2022, by and among Talos Energy Inc., as holdings, Talos Production Inc., as borrower, each other credit party thereto, JPMorgan Chase Bank, N.A., as administrative agent, each issuing bank, the swingline lender and the lenders party thereto. (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on August 05, 2022).
10.50	Incremental Agreement of Increasing Lenders, dated as of May 4, 2022, by and among DNB Capital LLC and Mizuho Bank, Ltd, as increasing lender, Talos Production Inc., as borrower, Talos Energy Inc., as holdings, JPMorgan Chase Bank, N.A., as administrative agent, swingline lender and issuing bank and Natixis, New York Branch, as issuing bank.(incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 10-Q (File No. 001-38497) filed with the SEC on August 05, 2022).
10.51	Incremental Agreement and Ninth Amendment to Credit Agreement, dated as of December 23, 2022, among Talos Energy Inc., Talos Production Inc., each other Credit Party, JPMorgan Chase Bank, N.A., as Administrative Agent, each Issuing Bank, the Swingline Lender and each of the Lenders (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on December 27, 2022).
10.52#	Form of Support Agreement, by and between Talos Energy Inc., EnVen Energy Corporation and the EnVen Supporting Stockholders (incorporated by reference to Exhibit 10.1 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on September 22, 2022).
10.53	Support Agreement, by and between EnVen Energy Corporation, Talos Energy Inc. and the Talos Supporting Stockholders (incorporated by reference to Exhibit 10.2 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on September 22, 2022).
10.54	Letter Agreement, dated February 13, 2023, by and between Talos Energy Inc., Riverstone Talos Energy EquityCo LLC, Riverstone Talos Energy DebtCo LLC, ILX Holdings II, LLC and Riverstone V Castex 2014 Holdings, L.P. (incorporated by reference to Exhibit 10.3 to Talos Energy Inc.'s Form 8-K (File No. 001-38497) filed with the SEC on February 14, 2023).
21.1*	List of Subsidiaries of Talos Energy Inc.
22.1*	List of Subsidiary Guarantors and Issuers of Guaranteed Securities.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
24.1*	Powers of Attorney (included on signature pages of this Part IV).

31.1*	Certification of Chief Executive Officer of Talos Energy Inc. pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer of Talos Energy Inc. pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certification of Chief Executive Officer and Chief Financial Officer of Talos Energy Inc. pursuant to 18 U.S.C. § 1350, as adopted pursuant to the Sarbanes-Oxley Act of 2002.
99.1*	Netherland, Sewell & Associates, Inc. reserve report for Talos Energy Inc. as of December 31, 2022.
101.INS*	Inline XBRL Instance.
101.SCH*	Inline XBRL Taxonomy Extension Schema.
101.CAL*	Inline XBRL Taxonomy Extension Calculation.
101.DEF*	Inline XBRL Taxonomy Extension Definition.
101.LAB*	Inline XBRL Taxonomy Extension Label.
101.PRE*	Inline XBRL Taxonomy Extension Presentation.
104*	Cover Page Interactive Data File – The cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

*	Filed herewith.
**	Furnished herewith.
†	Identifies management contracts and compensatory plans or arrangements.
#	Certain schedules, annexes or exhibits have been omitted pursuant to Item 601(a)(5) of Regulation S-K, but will be furnished supplementally to the SEC upon request.

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

TALOS ENERGY INC.

Date:	February 28, 2023	By:	/s/ Shannon E. Young III
			Shannon E. Young III
			Executive Vice President and Chief Financial Officer

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Timothy S. Duncan and Shannon E. Young III, and each of them, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this report, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming that all said attorneys-in-fact and agents, or any of them or their or his or her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Timothy S. Duncan Timothy S. Duncan	Chief Executive Officer (Principal Executive Officer, Director)	February 28, 2023
/s/ Shannon E. Young III Shannon E. Young III	Chief Financial Officer (Principal Financial Officer, Authorized Signatory)	February 28, 2023
/s/ Gregory Babcock Gregory Babcock	Chief Accounting Officer (Principal Accounting Officer, Authorized Signatory)	February 28, 2023
/s/ Paula R. Glover Paula R. Glover	Director	February 28, 2023
/s/ Neal P. Goldman Neal P. Goldman	Director	February 28, 2023
/s/ John “Brad” Juneau John “Brad” Juneau	Director	February 28, 2023
/s/ Donald R. Kendall, Jr. Donald R. Kendall, Jr.	Director	February 28, 2023
/s/ Richard Sherrill Richard Sherrill	Director	February 28, 2023
/s/ Charles M. Sledge Charles M. Sledge	Director	February 28, 2023
/s/ Shandell Szabo Shandell Szabo	Director	February 28, 2023

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Talos Energy Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Talos Energy Inc. (the Company) as of December 31, 2022 and 2021, the related consolidated statements of operations, changes in stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and the financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 28, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

	Depreciation, depletion and amortization of proved oil and gas properties.
Description of the Matter	At December 31, 2022, the net book value of the Company's proved oil and gas properties was \$2.5 billion, and depreciation, depletion and amortization (DD&A) expense was \$411 million for the year then ended. As described in Note 2 to the consolidated financial statements, the Company follows the full cost method of accounting for its oil and gas properties. DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method based on proved oil and gas reserves, as estimated by the Company's internal reservoir engineers.

	Proved oil and gas reserves are prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Judgment is required by the Company's internal reservoir engineers in evaluating geological and engineering data when estimating oil and gas reserves. Estimating reserves also requires the selection and evaluation of inputs, including historical production, oil and gas price assumptions, future operating, and capital costs assumptions, among others. Because of the complexity involved in estimating oil and gas reserves, management engaged independent petroleum engineers to audit the proved oil and gas reserve estimates prepared by the Company's internal reservoir engineers for all properties as of December 31, 2022. Auditing the Company's DD&A expense calculation is complex because of the use of the work of the internal reservoir engineers and independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating proved oil and gas reserves.
How We Addressed the Matter in Our Audit	We obtained an understanding, evaluated the design, and tested the operating effectiveness of the Company's controls that address the risks of material misstatement relating to the DD&A expense calculation, including management's controls over the completeness and accuracy of the financial data provided to the engineers for use in estimating oil and gas reserves. Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company's internal reservoir engineers responsible for overseeing the preparation of the reserve estimates and the independent petroleum engineers used to audit the proved oil and gas reserve estimates. On a sample basis, we tested the completeness and accuracy of the financial data used in the estimation of proved oil and gas reserves by agreeing significant inputs to source documentation, where available, and assessing the inputs for reasonableness based on review of corroborative evidence and consideration of any contrary evidence. Additionally, we performed analytic and lookback procedures on select inputs into the oil and gas reserve estimate. Finally, we tested that the DD&A expense calculations are based on the appropriate proved oil and gas reserve balances from the Company's reserve report.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 2010.

Houston, Texas
February 28, 2023

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of Talos Energy Inc.

Opinion on Internal Control Over Financial Reporting

We have audited Talos Energy Inc.'s internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Talos Energy Inc. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2022 and 2021, the related consolidated statements of operations, changes in stockholders' equity (deficit), and cash flows for each of the three years in the period ended December 31, 2022, and the related notes and the financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the consolidated financial statements") and our report dated February 28, 2023 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Houston, Texas
February 28, 2023

TALOS ENERGY INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share amounts)

	Year Ended December 31,	
	2022	**2021**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 44,145	$ 69,852
Accounts receivable:		
Trade, net	150,598	173,241
Joint interest, net	54,697	28,165
Other, net	6,684	18,062
Assets from price risk management activities	25,029	967
Prepaid assets	84,759	48,042
Other current assets	1,917	1,674
Total current assets	367,829	340,003
Property and equipment:		
Proved properties	5,964,340	5,232,479
Unproved properties, not subject to amortization	154,783	219,055
Other property and equipment	30,691	29,091
Total property and equipment	6,149,814	5,480,625
Accumulated depreciation, depletion and amortization	(3,506,539)	(3,092,043)
Total property and equipment, net	2,643,275	2,388,582
Other long-term assets:		
Assets from price risk management activities	7,854	2,770
Equity method investments	1,745	—
Other well equipment inventory	25,541	17,449
Operating lease assets	5,903	5,714
Other assets	6,479	12,297
Total assets	$ 3,058,626	$ 2,766,815
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 128,174	$ 85,815
Accrued liabilities	219,769	130,459
Accrued royalties	52,215	59,037
Current portion of long-term debt	—	6,060
Current portion of asset retirement obligations	39,888	60,311
Liabilities from price risk management activities	68,370	186,526
Accrued interest payable	36,340	37,542
Current portion of operating lease liabilities	1,943	1,715
Other current liabilities	60,359	33,061
Total current liabilities	607,058	600,526
Long-term liabilities:		
Long-term debt, net of discount and deferred financing costs	585,340	956,667
Asset retirement obligations	501,773	373,695
Liabilities from price risk management activities	7,872	13,938
Operating lease liabilities	14,855	16,330
Other long-term liabilities	176,152	45,006
Total liabilities	1,893,050	2,006,162
Commitments and contingencies (Note 12)		
Stockholders' equity:		
Preferred stock, $0.01 par value; 30,000,000 shares authorized and no shares issued or outstanding as of December 31, 2022 and 2021	—	—
Common stock $0.01 par value; 270,000,000 shares authorized; 82,570,328 and 81,881,477 shares issued and outstanding as of December 31, 2022 and 2021, respectively	826	819
Additional paid-in capital	1,699,799	1,676,798
Accumulated deficit	(535,049)	(916,964)
Total stockholders' equity	1,165,576	760,653
Total liabilities and stockholders' equity	$ 3,058,626	$ 2,766,815

See accompanying notes.

TALOS ENERGY INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except share amounts)

	Year Ended December 31,		
	2022	**2021**	**2020**
Revenues:			
Oil	1,365,148	$ 1,064,161	$ 506,788
Natural gas	227,306	130,616	53,714
NGL	59,526	49,763	15,434
Total revenues	1,651,980	1,244,540	575,936
Operating expenses:			
Lease operating expense	308,092	283,601	246,564
Production taxes	3,488	3,363	1,054
Depreciation, depletion and amortization	414,630	395,994	364,346
Write-down of oil and natural gas properties	—	18,123	267,916
Accretion expense	55,995	58,129	49,741
General and administrative expense	99,754	78,677	79,175
Other operating (income) expense	33,902	32,037	(11,550)
Total operating expenses	915,861	869,924	997,246
Operating income (expense)	736,119	374,616	(421,310)
Interest expense	(125,498)	(133,138)	(99,415)
Price risk management activities income (expense)	(272,191)	(419,077)	87,685
Equity method investment income	14,222	—	—
Other income (expense)	31,800	(6,988)	3,018
Net income (loss) before income taxes	384,452	(184,587)	(430,022)
Income tax benefit (expense)	(2,537)	1,635	(35,583)
Net income (loss)	$ 381,915	$ (182,952)	$ (465,605)
Net income (loss) per common share:			
Basic	$ 4.63	$ (2.24)	$ (6.88)
Diluted	$ 4.56	$ (2.24)	$ (6.88)
Weighted average common shares outstanding:			
Basic	82,454	81,769	67,664
Diluted	83,683	81,769	67,664

See accompanying notes.

TALOS ENERGY INC.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY (DEFICIT)
(In thousands, except share amounts)

	Shares		Par Value		Additional		Total
	Common Stock	Preferred Stock	Common Stock	Preferred Stock	Paid- In Capital	Accumulated Deficit	Stockholders Equity (Deficit)
Balance at December 31, 2019	54,197,004	—	$ 542	$ —	$ 1,346,142	$ (268,407)	$ 1,078,277
Equity-based compensation	—	—	—	—	16,462	—	16,462
Equity-based compensation tax withholdings	—	—	—	—	(827)	—	(827)
Equity-based compensation stock issuances	180,525	—	1	—	(1)	—	—
Issuance of preferred stock (Note 3)	—	110,000	—	1	156,199	—	156,200
Conversion of preferred stock into common stock (Note 3)	11,000,000	(110,000)	110	(1)	(109)	—	—
Issuance of common stock	8,250,000	—	83	—	70,658	—	70,741
Issuance of common stock for acquisitions (Note 3)	4,602,460	—	46	—	35,347	—	35,393
Issuance of common stock for debt exchange (Note 7)	3,050,000	—	31	—	35,929	—	35,960
Net loss	—	—	—	—	—	(465,605)	(465,605)
Balance at December 31, 2020	81,279,989	—	813	—	1,659,800	(734,012)	926,601
Equity-based compensation	—	—	—	—	20,165	—	20,165
Equity-based compensation tax withholdings	—	—	—	—	(3,161)	—	(3,161)
Equity-based compensation stock issuances	601,488	—	6	—	(6)	—	—
Net loss	—	—	—	—	—	(182,952)	(182,952)
Balance at December 31, 2021	81,881,477	—	819	—	1,676,798	(916,964)	760,653
Equity-based compensation	—	—	—	—	27,611	—	27,611
Equity-based compensation tax withholdings	—	—	—	—	(4,603)	—	(4,603)
Equity-based compensation stock issuances	688,851	—	7	—	(7)	—	—
Net income	—	—	—	—	—	381,915	381,915
Balance at December 31, 2022	82,570,328	—	$ 826	$ —	$ 1,699,799	$ (535,049)	$ 1,165,576

See accompanying notes.

TALOS ENERGY INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2022	2021	2020
Cash flows from operating activities:			
Net income (loss)	$ 381,915	$ (182,952)	$ (465,605)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, amortization and accretion expense	470,625	454,123	414,087
Write-down of oil and natural gas properties and other well inventory	—	23,729	268,615
Amortization of deferred financing costs and original issue discount	14,379	13,382	6,804
Equity-based compensation expense	15,953	10,992	8,669
Price risk management activities expense (income)	272,191	419,077	(87,685)
Net cash received (paid) on settled derivative instruments	(425,559)	(290,164)	143,905
Equity method investment income	(14,222)	—	—
Loss (gain) on extinguishment of debt	1,569	13,225	(1,662)
Settlement of asset retirement obligations	(69,596)	(67,988)	(43,933)
Gain on sale of assets	303	(687)	—
Changes in operating assets and liabilities:			
Accounts receivable	14,927	(35,396)	(34,645)
Other current assets	(36,545)	(18,901)	35,934
Accounts payable	24,258	(6,261)	27,096
Other current liabilities	73,531	64,800	4,200
Other non-current assets and liabilities, net	(13,990)	14,409	26,143
Net cash provided by operating activities	709,739	411,388	301,923
Cash flows from investing activities:			
Exploration, development and other capital expenditures	(323,164)	(293,331)	(362,942)
Cash paid for acquisitions, net of cash acquired	(3,500)	(5,399)	(315,962)
Proceeds from sale of property and equipment, net	1,937	4,983	—
Contributions to equity method investees	(2,250)	—	—
Proceeds from sale of equity method investment	15,000	—	—
Net cash used in investing activities	(311,977)	(293,747)	(678,904)
Cash flows from financing activities:			
Proceeds from issuance of common stock	—	—	71,100
Issuance of senior notes	—	600,500	—
Redemption of senior notes and other long-term debt	(18,184)	(356,803)	(5,364)
Proceeds from Bank Credit Facility	85,000	100,000	350,000
Repayment of Bank Credit Facility	(460,000)	(365,000)	(60,000)
Deferred financing costs	(189)	(27,833)	(1,287)
Other deferred payments	—	(7,921)	(11,921)
Payments of finance lease	(25,493)	(21,804)	(17,509)
Employee stock awards tax withholdings	(4,603)	(3,161)	(827)
Net cash provided by (used in) financing activities	(423,469)	(82,022)	324,192
Net increase (decrease) in cash and cash equivalents	(25,707)	35,619	(52,789)
Cash and cash equivalents:			
Balance, beginning of period	69,852	34,233	87,022
Balance, end of period	$ 44,145	$ 69,852	$ 34,233
Supplemental non-cash transactions:			
Capital expenditures included in accounts payable and accrued liabilities	$ 105,773	$ 45,761	$ 74,957
Debt exchanged for common stock	$ —	$ —	$ 35,960
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 91,809	$ 68,891	$ 67,443

See accompanying notes.

Note 1 — Organization, Nature of Business and Basis of Presentation

Organization and Nature of Business

Talos Energy Inc. (the "Parent Company") is a Delaware corporation originally incorporated on November 14, 2017. On May 10, 2018, the Parent Company consummated a combination between Talos Energy LLC and Stone Energy Corporation ("Stone") (such combination, "Stone Combination"). Talos Energy LLC, which was the acquirer of Stone for financial reporting and accounting purposes, was formed in 2011 and commenced commercial operations on February 6, 2013. The Parent Company conducts all business operations through its operating subsidiaries, owns no operating assets and has no material operations, cash flows or liabilities independent of its subsidiaries. The Parent Company's common stock is traded on the New York Stock Exchange under the ticker symbol "TALO."

The Parent Company (including its subsidiaries, collectively "Talos" or the "Company") is a technically driven independent exploration and production company focused on safely and efficiently maximizing long-term value through its operations, currently in the United States ("U.S.") and offshore Mexico both through upstream oil and gas exploration and production and the development of carbon capture and sequestration ("CCS") opportunities. The Company leverages decades of technical and offshore operational expertise in the acquisition, exploration and development of assets in key geological trends that are present in many offshore basins around the world. With a focus on environmental stewardship, the Company also utilizes its expertise to explore opportunities to reduce industrial emissions through the Company's CCS initiatives along the coast of the U.S. Gulf of Mexico.

Basis of Presentation and Consolidation

The Consolidated Financial Statements have been prepared in accordance with GAAP and include the accounts of the Parent Company and entities in which the Parent Company holds a controlling financial interest. Both majority-owned subsidiaries and any variable interest entity in which the Parent Company is the primary beneficiary are consolidated. All intercompany transactions have been eliminated. All adjustments are of a normal, recurring nature and are necessary to fairly present the financial position, results of operations and cash flows for the periods reflected herein.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements, the reported amounts of revenues and expenses during the reporting periods and the reported amounts of proved oil and natural gas reserves. Actual results could differ from those estimates.

Segments

The Company has two operating segments: (i) exploration and production of oil, natural gas and NGLs ("Upstream Segment") and (ii) CCS ("CCS Segment"). The Upstream Segment is the Company's only reportable segment. The legal entities included in the CCS Segment have been designated as unrestricted, non-guarantor subsidiaries of the Company for purposes of the Bank Credit Facility (as defined in Note 2 — *Summary of Significant Accounting Policies*) and indenture governing the senior notes. See additional information in Note 13 — *Segment Information.*

Note 2 — Summary of Significant Accounting Policies

Overview of Significant Accounting Policies

Cash and Cash Equivalents — The Company presents cash as "Cash and cash equivalents" on the Company's Consolidated Balance Sheets. The Company considers all cash, money market funds and highly liquid investments with an original maturity of three months or less as cash and cash equivalents. Cash and cash equivalents are carried at cost, which approximates fair value.

Accounts Receivable and Allowance for Expected Credit Losses — Accounts receivable are stated at the historical carrying amount net of an allowance for expected credit losses. At each reporting period, the recoverability of material receivables is assessed using historical data, current market conditions and reasonable and supported forecasts of future economic conditions to determine their expected collectability. A loss-rate methodology is used to estimate the allowance for expected credit losses to be accrued on material receivables to reflect the net amount to be collected. As of December 31, 2022 and 2021, the Company had allowances of $10.7 million and $15.1 million, respectively, presented net in accounts receivable on the Consolidated Balance Sheets.

The Company presented $3.2 million and $10.0 million of long-term refund claims for value added taxes paid in Mexico in “Other assets” on the Consolidated Balance Sheets as of December 31, 2022 and 2021, respectively. Current refund claims for value added taxes paid in Mexico of $1.7 million and $3.9 million is presented net of an allowance in “Other” accounts receivable on the Consolidated Balance Sheets as of December 31, 2022 and 2021, respectively.

Price Risk Management Activities — The Company uses commodity price derivatives to manage fluctuating oil and natural gas market risks. The Company periodically enters into commodity derivative contracts, which may require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of oil or natural gas without the exchange of underlying volumes.

Commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts and changes in the unrealized fair value recorded in earnings each period. Realized gains and losses on the settlement of commodity derivatives and changes in their unrealized gains and losses are reported in “Price risk management activities income (expense)” on the Consolidated Statements of Operations. The Company classifies cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of the Company’s oil and natural gas operations, they are classified as cash flows from operating activities. The Company does not enter into derivative agreements for trading or other speculative purposes.

The commodity derivative’s fair value reflects the Company’s best estimate with priority based upon exchange or over-the-counter quotations. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, the Company then utilizes other valuation techniques or models to estimate market values. These modeling techniques require the Company to make estimations of future prices, price correlation, market volatility and liquidity. The Company’s actual results may differ from its estimates, and these differences can be favorable or unfavorable.

Prepaid Assets — Prepaid assets primarily represent prepaid subscriptions, insurance, progress payments for well equipment and deposits with the Office of Natural Resources Revenue (“ONRR”). The progress payments made for well equipment relate to long lead time items which the Company has not taken title to as of period end. The deposits with ONRR represent the Company’s estimated federal royalties payable within thirty days of the production date. On a monthly basis the Company adjusts the deposit based on actual royalty payments remitted to the ONRR.

Accounting for Oil and Natural Gas Activities — The Company follows the full cost method of accounting for oil and natural gas exploration and development activities. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves are capitalized. These capitalized amounts include the internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, dry hole costs and geological and geophysical costs are capitalized into the full cost pool, which is subject to amortization and assessed for impairment on a quarterly basis through a ceiling test calculation as discussed below.

Capitalized costs associated with proved reserves are amortized on a country-by-country basis over the life of the total proved reserves using the unit of production method, computed quarterly. Conversely, capitalized costs associated with unproved properties and related geological and geophysical costs, exploration wells currently drilling and capitalized interest are initially excluded from the amortizable base. The Company transfers unproved property costs into the amortizable base when properties are determined to have proved reserves or when the Company has completed an unproved properties evaluation resulting in an impairment. The Company evaluates each of these unproved properties individually for impairment at least annually. Additionally, the amortizable base includes future development costs, dismantlement, restoration and abandonment costs, net of estimated salvage values, and geological and geophysical costs incurred that cannot be associated with specific unproved properties or prospects in which the Company owns a direct interest. The Company capitalizes overhead costs that are directly related to exploration, acquisition and development activities.

The Company's capitalized costs are limited to a ceiling based on the present value of future net revenues from proved reserves, computed using a discount factor of 10%, plus the lower of cost or estimated fair value of unproved oil and natural gas properties not being amortized less the related tax effects. Generally, any costs in excess of the ceiling are recognized as a non-cash "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations and an increase to "Accumulated depreciation, depletion and amortization" on the Company's Consolidated Balance Sheets. The expense may not be reversed in future periods, even though higher oil, natural gas and NGL prices may subsequently increase the ceiling. The Company performs this ceiling test calculation each quarter. In accordance with the SEC rules and regulations, the Company utilizes SEC Pricing when performing the ceiling test. The Company also holds prices and costs constant over the life of the reserves, even though actual prices and costs of oil and natural gas are often volatile and may change from period to period.

Under the full cost method of accounting for oil and natural gas operations, assets whose costs are currently being depreciated, depleted or amortized are assets in use in the earnings activities of the enterprise and do not qualify for capitalization of interest cost. Investments in unproved properties for which exploration and development activities are in progress and other major development projects that are not being currently depreciated, depleted or amortized are assets qualifying for capitalization of interest costs.

When the Company sells or conveys interests in oil and natural gas properties, the Company reduces its oil and natural gas reserves for the amount attributable to the sold or conveyed interest. The Company treats sales proceeds on non-significant sales as reductions to the cost of the Company's oil and natural gas properties. The Company does not recognize a gain or loss on sales of oil and natural gas properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves.

***Accounting for CCS Development Activities* —** Expenditures for CCS during the preliminary stages of development are charged to expense as incurred until the development of the project is considered probable. These costs primarily include professional fees associated with front-end engineering and design work, costs of securing necessary regulatory approvals and other preliminary investigation and development activities.

The pre-construction stage of project development begins once construction of the individual project becomes probable. Certain costs may be capitalized prior to a project becoming probable and include: land acquisition costs; detailed engineering design work; and costs that have an alternative use (e.g., stratigraphic test well). Capitalized development costs are included as a component of other long-term assets during the pre-construction stage of development. These capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

CCS contracts that convey subsurface rights for geologic pore space are accounted for as intangible assets and amortized over their estimated useful life. As of December 31, 2022 and 2021, the Company had $1.4 million and nil intangible assets, respectively. These assets are classified as other long-term assets and included in "Other assets" on the Consolidated Balance Sheets. Costs to renew or extend the life of CCS intangible assets are capitalized and amortized over the remaining useful life.

***Other Property and Equipment* —** Other property and equipment is recorded at cost and consists primarily of leasehold improvements, office furniture and fixtures and computer hardware. Acquisitions and betterments are capitalized; maintenance and repairs are expensed as incurred. Depreciation is provided using the straight-line method over estimated useful lives of three to ten years.

Equity Method Investments — If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, the Company accounts for its investment using the equity method if the Company's ownership interest is between 3% and 50%, unless the Company's interest is so minor that it has virtually no influence over the investee's operating and financial policies. For all other types of investments, the Company applies the equity method of accounting if its ownership interest is between 20% and 50% and the Company's exercise significant influence over the investee's operating and financial policies. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for the Company's proportionate share of earnings, losses, contributions and distributions. Investments accounted for using the equity method are reflected as "Equity method investments" on the Consolidated Balance Sheets. The equity in earnings of an investee are reflected in "Equity method investment income (loss)" on the Consolidated Statement of Operations. The gain or loss from the full or partial sale of an equity method investment is presented in the same line item in which the Company reports the equity in earnings of the investee.

The Company assesses equity method investments for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred if the loss is deemed to be other-than-temporary. When the loss is deemed to be other-than-temporary, the carrying value of the equity method investment is written down to fair value. The impairment charge is included as a component of the Company's share of the earning or losses of the investee. No impairment charges have been recorded during the years ended December 31, 2022, 2021 and 2020.

Other Well Equipment Inventory — Other well equipment inventory primarily represents the cost of equipment to be used in the Company's oil and natural gas drilling and development activities such as drilling pipe, tubulars and certain wellhead equipment. When well equipment is supplied to wells, the cost is capitalized in oil and gas properties, and if such property is jointly owned, the proportionate costs will be reimbursed by third party participants. The Company's well equipment is stated at the lower of cost or net realizable value. The Company recorded nil, $5.6 million and $0.7 million of impairment to adjust inventory to net realizable value, which was expensed and reflected in "Other operating (income) expense" on the Consolidated Statements of Operations, during the years ended December 31, 2022, 2021 and 2020, respectively.

Leases — At inception, contracts are reviewed to determine whether the agreement contains a lease. To the extent an arrangement is determined to include a lease, it is classified as either an operating or a finance lease, which dictates the pattern of expense recognition in the income statement. Operating leases are reflected as "Operating lease assets," "Current portion of operating lease liabilities" and "Operating lease liabilities" on the Consolidated Balance Sheets. Finance leases are included in "Property and equipment," "Other current liabilities" and "Other long-term liabilities" on the Consolidated Balance Sheets.

A right-of-use ("ROU") asset representing our right to use an underlying asset for the lease term and a lease liability representing our obligation to make lease payments arising from the lease are recognized on the Consolidated Balance Sheets for all leases, regardless of classification. The ROU asset is initially measured as the present value of the lease liability adjusted for any payments made prior to lease commencement, including any initial direct costs incurred and incentives received. Lease liabilities are initially measured at the present value of future minimum lease payments, excluding variable lease payments, over the lease term. As most of our leases do not provide an implicit rate, the Company generally uses an incremental borrowing rate based on the estimated rate of interest for collateralized borrowing over a similar term of the lease payments at commencement date.

The Company has elected to account for lease and non-lease components in its contracts as a single lease component for all asset classes except for our leased floating production vessel class. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. The Company has elected, as an accounting policy, not to record leases with terms of twelve months or less (i.e., short-term) on the Consolidated Balance Sheets. See Note 5 — *Leases* for additional information.

Debt Issuance Costs — The Company presents debt issuance costs associated with revolving line-of-credit arrangements as a reduction of the carrying value of long-term debt.

Asset Retirement Obligations — The Company has obligations associated with the retirement of its oil and natural gas wells and related infrastructure. The Company has obligations to plug wells when production on those wells is exhausted, when the Company no longer plans to use them or when the Company abandons them. The Company accrues a liability with respect to these obligations based on its estimate of the timing and amount to replace, remove or retire the associated assets.

In estimating the liability associated with its asset retirement obligations, the Company utilizes several assumptions, including a credit-adjusted risk-free interest rate, estimated costs of decommissioning services, estimated timing of when the work will be performed and a projected inflation rate. Changes in estimate represent changes to the expected amount and timing of payments to settle its asset retirement obligations. Typically, these changes result from obtaining new information about the timing of its obligations to plug and abandon oil and natural gas wells and the costs to do so. After initial recording, the liability is increased for the passage of time, with the increase being reflected as "Accretion expense" on the Company's Consolidated Statements of Operations. If the Company incurs an amount different from the amount accrued for asset retirement obligations, the Company recognizes the difference as an adjustment to proved properties.

Decommissioning Obligations — Certain counterparties in divestiture transactions or third parties in existing leases that have filed for bankruptcy protection or undergone associated reorganizations may not be able to perform required abandonment obligations. The Company may be held jointly and severally liable for the decommissioning of various facilities and related wells. The Company accrues losses associated with decommissioning obligations when such losses are probable and reasonably estimable. When there is a range of possible outcomes, the amount accrued is the most likely outcome within the range. If no single outcome within the range is more likely than the others, the minimum amount in the range is accrued. These accruals may be adjusted as additional information becomes available. In addition, when decommissioning obligations are reasonably possible, the Company discloses an estimate for a possible loss or range of loss (or a statement that such an estimate cannot be reasonably made). See Note 12 — *Commitments & Contingencies* for additional information.

Share-Based Compensation — Certain of the Company's employees participate in its equity-based compensation plan. The Company measures all employee equity-based compensation awards at fair value on the date awards are granted to its employees.

The fair value of the stock-based awards is determined at the date of grant and is not remeasured for awards classified as equity unless the award is modified. Liability classified awards are remeasured at each reporting period. The Company records share-based compensation, net of actual forfeitures, for the RSUs and PSUs in "General and administrative expense" on the Consolidated Statements of Operations, net of amounts capitalized to oil and gas properties. See Note 8 — *Employee Benefits Plans and Share-Based Compensation* for additional information.

Restricted Stock Units ("RSUs") — Share-based compensation is based on the market price of the Company's common stock on the grant date and recognized over the requisite service period using the straight-line method.

Performance Share Units ("PSUs") with Market Based Conditions — Share-based compensation is based on the grant date fair value determined using a Monte Carlo valuation model for awards with a market condition and recognized over the requisite service period using the straight-line method. Estimates used in the Monte Carlo valuation model are considered highly-complex and subjective. The number of shares of common stock issuable upon vesting ranges from zero to 200% of the number of PSUs granted based on the Company's total shareholder return ("TSR"). Share-based compensation related to PSUs with a market condition are recognized as the requisite service period is fulfilled, even if the market condition is not achieved.

PSUs with Performance Based Conditions — Share-based compensation is based on the market price of the Company's common stock on the grant date and recognized over the requisite service period using the straight-line method for awards with a performance condition. The Company recognizes compensation cost for awards with performance conditions if and when the Company concludes that it is probable that the performance condition will be achieved. The Company reassesses the probability of vesting at each reporting period for awards with performance conditions and adjusts compensation cost based on its probability assessment. The Company recognizes a cumulative catch-up adjustment for such changes in its probability assessment in subsequent reporting periods, using the grant date fair value of the award whose terms reflect the updated probable performance condition (which could be either a reversal or increase in expense). The number of shares of common stock issuable upon vesting ranges from zero to 200% of the number of PSUs granted based on a metric associated with the Company's own operations or activities.

Revenue Recognition — Revenues are recorded based from the sale of oil, natural gas and NGL quantities sold to purchasers. The Company records revenues from the sale of oil, natural gas and NGLs based on quantities of production sold to purchasers under short-term contracts (less than twelve months) at market prices when delivery to the customer has occurred, title has transferred, prices are fixed and determinable and collection is reasonably assured. This occurs when production has been delivered to a pipeline or when a barge lifting has occurred. The Company recognizes transportation costs as a component of lease operating expense when it is the shipper of the product. Each unit of product typically represents a separate performance obligation, therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Gas Imbalances — Revenues are recorded based on the actual sales volumes sold to purchasers. An imbalance receivable or payable is recorded only to the extent the imbalance is in excess of its share of remaining proved developed reserves in an underlying property. Our imbalances are presented gross on our Consolidated Balance Sheets. At December 31, 2022 and 2021, our imbalance receivable was approximately $1.7 million and $1.7 million, respectively, and imbalance payable was approximately $2.5 million and $2.5 million, respectively.

Production Handling Fees — The Company presents certain reimbursements for costs from certain third parties as a reduction of "Lease operating expense" on the Consolidated Statements of Operations.

ONRR Federal Royalty Refund — Included within "Other operating (income) expense" on the Consolidated Statements of Operations is income from the Company's multi-year federal royalty refund claim from the ONRR. The Company records income when a refund is filed and its collection is reasonably assured. The refunds for the years ended December 31, 2022, 2021 and 2020 were $0.6 million, nil and $8.9 million, respectively.

Income Taxes — The Company records current income taxes based on estimates of current taxable income and provides for deferred income taxes to reflect estimated future income tax payments and receipts. The impact to changes in tax laws are recorded in the period the change is enacted. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. The Company classifies all deferred tax assets and liabilities, along with any related valuation allowance, as long-term on the Consolidated Balance Sheets.

The realization of deferred tax assets depends on recognition of sufficient future taxable income during periods in which those temporary differences are deductible. The Company reduces deferred tax assets by a valuation allowance when, based on estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The deferred tax asset estimates are subject to revision, either up or down, in future periods based on new facts or circumstances. In evaluating the Company's valuation allowances, the Company considers cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in carryback years, tax planning strategies and future taxable income for each of its taxable jurisdictions, the latter two of which involve the exercise of significant judgment. Changes to the Company's valuation allowances could materially impact its results of operations.

The Company's policy is to classify interest and penalties associated with underpayment of income taxes as "Interest expense" and "General and administrative expense" on the Consolidated Statements of Operations, respectively.

Income (Loss) Per Share — Basic net income per common share ("EPS") is computed by dividing net income (loss) by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be antidilutive, diluted EPS includes the impact of RSUs, PSUs and outstanding warrants. See Note 10 — *Income (Loss) Per Share* for additional information.

Fair Value Measure of Financial Instruments — Financial instruments generally consist of cash and cash equivalents, accounts receivable, commodity derivatives, accounts payable and debt. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to the highly liquid nature of these instruments.

Current fair value accounting standards define fair value, establish a consistent framework for measuring fair value and stipulate the related disclosure requirements for each major asset and liability category measured at fair value on either a recurring or nonrecurring basis. These standards also clarify fair value is an exit price, presenting the amount that would be received to sell an asset or paid to transfer a liability, in an orderly transaction between market participants. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value depending on the degree to which they are observable as follows:

- ***Level 1 –*** Inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- ***Level 2 –*** Inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial statement.
- ***Level 3 –*** Inputs to the valuation methodology are unobservable (little or no market data), which require the reporting entity to develop its own assumptions, and are significant to the fair value measurement.

Assets and liabilities measured at fair value are based on one or more of three valuation techniques. The valuation techniques are as follows:

- ***Market Approach –*** Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities.
- ***Cost Approach –*** Amount that would be required to replace the service capacity of an asset (replacement cost).
- ***Income Approach –*** Techniques to convert expected future cash flows to a single present value amount based on market expectations (including present value techniques, option-pricing and excess earnings models).

Authoritative guidance on financial instruments requires certain fair value disclosures to be presented. The estimated fair value amounts have been determined using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Variable Interest Entities — Upon inception of a contractual agreement, the Parent Company performs an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a variable interest Entity ("VIE"). The Parent Company assesses all aspects of its interests in an entity and uses judgment when determining if it is the primary beneficiary. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. A reassessment of the primary beneficiary conclusion is conducted when there are changes in the facts and circumstances related to a VIE. See Note 11 — *Related Party Transactions* for additional information.

Concentration of Credit Risk

Consisting principally of cash and cash equivalents, accounts receivable and commodity derivatives, the Company is subject to concentrated financial instruments credit risk.

Cash and cash equivalents balances are maintained in financial institutions, which at times, exceed federally insured limits. The Company monitors the financial condition of these institutions and has not experienced losses on these accounts.

Commodity derivatives are entered into with registered swap dealers, all of which participate in the Company's senior reserve-based revolving credit facility (the "Bank Credit Facility"). The Company monitors the financial condition of these institutions and has not experienced losses due to counterparty default on these instruments.

The Company markets substantially all of its oil and natural gas production, and substantially all of its revenues are attributable to the U.S. The majority of the Company's oil, natural gas and NGL production is sold to customers under short-term (less than 12 months) contracts at market-based prices. The Company's customers consist primarily of major oil and natural gas companies, well-established oil and pipeline companies and independent oil and gas producers and suppliers. The Company performs ongoing credit evaluations of its customers and provide allowances for probable credit losses when necessary. The percent of consolidated revenue of major customers, those whose total represented 10% or more of the Company's oil, natural gas and NGL revenues, was as follows:

	Year Ended December 31,		
	2022	2021	2020
Shell Trading (US) Company	44%	45%	47%
Valero Energy Corporation	23%	**	**
Chevron Products Company	11%	29%	12%
Phillips 66	**	**	22%

** Less than 10%

The loss of a major customer could have material adverse effect on the Company in the short term. However, the Company believes it would be able to obtain other customers to market its oil, natural gas and NGL production.

Note 3 — Acquisitions

Asset Acquisitions

Acquisitions qualifying as an asset acquisition requires, among other items, that the cost of the assets acquired and liabilities assumed to be recognized on the Consolidated Balance Sheets by allocating the asset cost on a relative fair value basis. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and appropriate discount rates. These inputs required significant judgments and estimates by the Company's management at the time of the valuation. Transaction costs incurred on an asset acquisition are capitalized as a component of the assets acquired and any contingent consideration is recognized as the contingency is resolved.

Acquisition of LLOG Properties — On November 16, 2020, the Company completed the acquisition of select oil and natural gas assets from LLOG Exploration & Production Company, L.L.C. (the "LLOG Acquisition"). The oil and natural gas assets consist of interests in the Mississippi Canyon core area. The LLOG Acquisition was consummated pursuant to a Purchase and Sale Agreement executed on November 16, 2020 for $13.2 million in cash, inclusive of customary closing adjustments and $0.2 million of transaction related expenses.

Acquisition of Castex Energy 2005 — On August 5, 2020, the Company completed the acquisition of select oil and natural gas assets from affiliates of Castex Energy 2005 Holdco, LLC (the "Castex Energy 2005 Acquisition"). The Castex Energy 2005 Acquisition was consummated pursuant to a Purchase and Sale Agreement dated June 19, 2020 for consideration consisting of (i) $6.5 million in cash, (ii) 4.6 million shares of the Company's common stock valued at $35.4 million and (iii) $1.4 million in transaction related expenses, inclusive of customary closing adjustments.

Business Combinations

Acquisitions qualifying as business combinations are accounted for under the acquisition method of accounting, which requires, among other items, that assets acquired and liabilities assumed be recognized on the Consolidated Balance Sheets at their fair values as of the acquisition date. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of reserves, future operating and development costs, future commodity prices, estimated future cash flows and appropriate discount rates. These inputs required significant judgments and estimates at the time of the valuation.

EnVen Acquisition **—** On September 21, 2022, the Company executed a merger agreement to acquire EnVen Energy Corporation ("EnVen"), a private operator in the Deepwater U.S. Gulf of Mexico (the "EnVen Acquisition," and such agreement, the "EnVen Merger Agreement"). The Company incurred $9.0 million of transaction related costs for the year ended December 31, 2022. These costs are reflected in "General and administrative expense" on the Consolidated Statements of Operations.

Subsequent Event **—** On February 13, 2023, the Company completed the EnVen Acquisition for consideration consisting of (i) $207.3 million in cash and (ii) 43.8 million shares of the Company's common stock valued at $832.2 million. Due to the timing of the EnVen Acquisition, the Company is unable to estimate the purchase price allocation of such acquisition at this time.

ILX and Castex Acquisition **—** On February 28, 2020, the Company acquired the outstanding limited liability interests in certain wholly owned subsidiaries of ILX Holdings, LLC; ILX Holdings II, LLC; ILX Holdings III LLC and Castex Energy 2014, LLC, each a related party and an affiliate of the Riverstone Funds (as defined in Note 11 — *Related Party Transactions*) (the "Riverstone Sellers"), and Castex Energy 2016, LP (together with the Riverstone Sellers, the "Sellers") with an effective date of July 1, 2019 (collectively, the "ILX and Castex Acquisition"). The ILX and Castex Acquisition was consummated pursuant to separate Purchase and Sale Agreements, dated December 10, 2019 (as amended from time to time, the "Purchase Agreements") for aggregate consideration consisting of (i) $303.1 million in cash after customary closing adjustments and (ii) an aggregate 110,000 shares of a series of the Company's preferred stock designated as "Series A Convertible Preferred Stock" which subsequently converted to 11.0 million shares of the Company's common stock on March 30, 2020 (such common stock, the "Conversion Stock"). The Conversion Stock was valued at $156.2 million. The cash consideration was funded with borrowings under the Bank Credit Facility.

The Company incurred $12.1 million of transaction related costs, of which $8.7 million was recognized in the year ended December 31, 2020. These costs are reflected in "General and administrative expense" on the Consolidated Statements of Operations.

The following table presents revenue and net income attributable to the assets acquired in the ILX and Castex Acquisition:

	Year Ended December 31, 2020	
Revenue	$	126,857
Net loss	$	(6,011)

Pro Forma Financial Information (Unaudited) **—** The following supplemental pro forma financial information (in thousands, except per common share amounts), presents the consolidated results of operations for the year ended December 31, 2020 as if the ILX and Castex Acquisition had occurred on January 1, 2019. The unaudited pro forma information was derived from historical statements of operations of the Company and the Sellers adjusted to (i) include depletion expense applied to the adjusted basis of the oil and natural gas properties acquired, (ii) include interest expense to reflect borrowings under the Bank Credit Facility, (iii) eliminate the write-down of oil and natural gas properties on the assets acquired to reflect the pro-forma ceiling test calculation and (iv) include weighted average basic and diluted shares of common stock outstanding, which was calculated assuming the 11.0 million shares of Conversion Stock were issued to the Sellers. This information does not purport to be indicative of results of operations that would have occurred had the ILX and Castex Acquisition occurred on January 1, 2019, nor is such information indicative of any expected future results of operations.

	Year Ended December 31, 2020	
Revenue	$	634,921
Net loss	$	(449,988)
Basic net loss per common share	$	(6.48)
Diluted net loss per common share	$	(6.48)

Note 4 — Property, Plant and Equipment

Proved Properties

The Company's interests in oil and natural gas proved properties are located in the United States, primarily in the Gulf of Mexico deep and shallow waters. During 2022, 2021 and 2020, the Company's ceiling test computations resulted in a write-down of its U.S. oil and natural gas properties of nil, nil and $267.9 million, respectively. At December 31, 2022, its ceiling test computation was based on SEC pricing of $96.03 per Bbl of oil, $6.80 per Mcf of natural gas and $33.89 per Bbl of NGLs.

Unproved Properties

Unproved capitalized costs of oil and natural gas properties excluded from amortization relate to unevaluated properties associated with acquisitions, leases awarded in the U.S. Gulf of Mexico federal lease sales, certain geological and geophysical costs, expenditures associated with certain exploratory wells in progress and capitalized interest. Unproved properties also include expenditures associated with exploration and appraisal activities in Block 7 located in the shallow waters off the coast of Mexico's Tabasco state.

The following table sets forth a summary of the Company's oil and natural gas property costs not being amortized at December 31, 2022, by the year in which such costs were incurred (in thousands):

		Year Ended December 31,			
	Total	2022	2021	2020	2019 and Prior
Acquisition United States	$ 29,646	$ 2,221	$ —	$ 27,322	$ 103
Exploration United States	13,707	2,696	4,727	1,753	4,531
Exploration Mexico	111,430	1,170	3,460	13,853	92,947
Total unproved properties, not subject to amortization	$ 154,783	$ 6,087	$ 8,187	$ 42,928	$ 97,581

The excluded costs will be included in the amortization base as properties are evaluated and proved reserves are established or impairment is determined. The $111.4 million of capitalized exploration cost in Mexico relates to the Zama Field Development Plan for submission to the Mexican regulator for final approval. The Company expects to transfer the cost into the amortization base by 2024.

The Company's evaluation of unproved property located offshore Mexico resulted in a non-cash impairment of nil, $18.1 million and $0.1 million for the years ended December 31, 2022, 2021 and 2020, respectively, presented as "Write-down of oil and natural gas properties" on the Consolidated Statements of Operations. The non-cash impairment is primarily attributable to the Company's operations in offshore Mexico in Block 31 associated with the Company's non-consent of the proposed appraisal plan during the fourth quarter of 2021.

Asset Retirement Obligations

The asset retirement obligations included in the Consolidated Balance Sheets in current and non-current liabilities, and the changes in that liability were as follows (in thousands):

	Year Ended December 31,	
	2022	2021
Balance, beginning of period	$ 434,006	$ 442,269
Obligations acquired	—	433
Obligations incurred	1,140	52
Obligations settled	(69,596)	(67,988)
Obligations divested	(1,572)	(340)
Accretion expense	55,995	58,129
Changes in estimate[1]	121,688	1,451
Balance, end of period	$ 541,661	$ 434,006
Less: Current portion	39,888	60,311
Long-term portion	$ 501,773	$ 373,695

(1) Changes in estimate for the year ended December 31, 2022 were primarily due to an increase in estimated service costs.

Note 5 — Leases

The Company has operating leases principally for office space, drilling rigs, compressors and other equipment necessary to support the Company's operations. Additionally, the Company has a finance lease related to the use of the Helix Producer I (the "HP-I"), a dynamically positioned floating production facility that interconnects with the Phoenix Field through a production buoy. The HP-I is utilized in the Company's oil and natural gas development activities and the ROU asset was capitalized and included in proved property and depleted as part of the full cost pool. Once items are included in the full cost pool, they are indistinguishable from other proved properties. The capitalized costs within the full cost pool are amortized over the life of the total proved reserves using the unit-of-production method, computed quarterly. Costs associated with the Company's leases are either expensed or capitalized depending on how the underlying asset is utilized.

In November 2022, the Company exercised its option to extend the lease of the HP-I through June 1, 2024. The extension resulted in a remeasurement of the lease liability to $166.3 million and corresponding adjustment to proved property.

The lease costs described below are presented on a gross basis and do not represent the Company's net proportionate share of such amounts. A portion of these costs have been or may be billed to other working interest owners. The Company's share of these costs is included in property and equipment, lease operating expense or general and administrative expense, as applicable. The components of lease costs were as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Finance lease cost - interest on lease liabilities	$ 7,558	$ 11,453	$ 15,748
Operating lease cost, excluding short-term leases(1)	2,281	2,706	3,361
Short-term lease cost(2)	55,072	38,472	53,573
Variable lease cost(3)	1,450	1,356	543
Total lease cost	$ 66,361	$ 53,987	$ 73,225

(1) Operating lease cost reflect a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a straight-line basis.

(2) Short-term lease costs are reported at gross amounts and primarily represent costs incurred for drilling rigs, most of which are short-term contracts not recognized as a ROU asset and lease liability on the Consolidated Balance Sheets.

(3) Variable lease costs primarily represent differences between minimum payment obligations and actual operating charges incurred by the Company related to its long-term leases.

The present value of the fixed lease payments recorded as the Company's ROU asset and liability, adjusted for initial direct costs and incentives were as follows (in thousands):

	Year Ended December 31,	
	2022	2021
Operating leases:		
Operating lease assets	$ 5,903	$ 5,714
Current portion of operating lease liabilities	$ 1,943	$ 1,715
Operating lease liabilities	14,855	16,330
Total operating lease liabilities	$ 16,798	$ 18,045
Finance leases:		
Proved property	$ 166,261	$ 124,299
Other current liabilities	$ 16,306	$ 27,083
Other long-term liabilities	149,064	13,138
Total finance lease liabilities	$ 165,370	$ 40,221

The table below presents the lease maturity by year as of December 31, 2022 (in thousands). Such commitments are reflected at undiscounted values and are reconciled to the discounted present value recognized on the Consolidated Balance Sheets.

	Operating Leases	Finance Leases
2023	$ 3,774	$ 30,782
2024	3,579	30,782
2025	3,645	30,782
2026	3,712	30,782
2027	3,596	30,782
Thereafter	5,727	74,389
Total lease payments	$ 24,033	$ 228,299
Imputed interest	(7,235)	(62,929)
Total lease liabilities	$ 16,798	$ 165,370

The table below presents the weighted average remaining lease term and discount rate related to leases:

	Year Ended December 31,		
	2022	2021	2020
Weighted average remaining lease term:			
Operating leases	6.4 years	7.4 years	7.8 years
Finance leases	7.4 years	1.4 years	2.4 years
Weighted average discount rate:			
Operating leases	11.8%	11.9%	12.0%
Finance leases	9.2%	21.9%	21.9%

The table below presents the supplemental cash flow information related to leases (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Operating cash outflow from finance leases	$ 7,181	$ 11,453	$ 15,748
Operating cash outflow from operating leases	$ 3,722	$ 3,864	$ 2,648
ROU assets obtained in exchange for new finance lease liabilities	$ 166,261	$ —	$ —
ROU assets obtained in exchange for new operating lease liabilities	$ 474	$ 1,020	$ —

Note 6 — Financial Instruments

As of December 31, 2022 and 2021, the carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair values because of the short-term nature of these instruments.

Debt Instruments

The following table presents the carrying amounts, net of discount and deferred financing costs, and estimated fair values of the Company's debt instruments (in thousands):

	December 31, 2022		December 31, 2021	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
12.00% Second-Priority Senior Secured Notes – due January 2026	$ 590,132	$ 674,542	$ 588,838	$ 685,945
7.50% Senior Notes – due May 2022	$ —	$ —	$ 6,060	$ 6,145
Bank Credit Facility – matures November 2024	$ (4,792)	$ —	$ 367,829	$ 375,000

The carrying value of the senior notes are presented net of the original issue discount and deferred financing costs. Fair value is estimated (representing a Level 1 fair value measurement) using quoted secondary market trading prices.

The carrying amount of the Company's Bank Credit Facility is presented net of deferred financing costs. The fair value of the Bank Credit Facility is estimated based on the outstanding borrowings under the Bank Credit Facility since it is secured by the Company's reserves and the interest rates are variable and reflective of market rates (representing a Level 2 fair value measurement).

Oil and Natural Gas Derivatives

The Company attempts to mitigate a portion of its commodity price risk and stabilize cash flows associated with sales of oil and natural gas production. The Company utilizes oil and natural gas swaps and costless collars. Swaps are contracts where the Company either receives or pays depending on whether the oil or natural gas floating market price is above or below the contracted fixed price. Costless collars consist of a purchased put option and a sold call option with no net premiums paid to or received from counterparties. Collar contracts typically require payments by the Company if the NYMEX average closing price is above the ceiling price or payments to the Company if the NYMEX average closing price is below the floor price.

The Company has elected not to designate any of its derivative contracts for hedge accounting. Accordingly, commodity derivatives are recorded on the Consolidated Balance Sheets at fair value with settlements of such contracts, and changes in the unrealized fair value, recorded as "Price risk management activities income (expense)" on the Consolidated Statements of Operations in each period.

The following table presents the impact that derivatives, not designated as hedging instruments, had on its Consolidated Statements of Operations (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Net cash received (paid) on settled derivative instruments	$ (425,559)	$ (290,164)	$ 143,905
Unrealized gain (loss)	153,368	(128,913)	(56,220)
Price risk management activities income (expense)	$ (272,191)	$ (419,077)	$ 87,685

The following tables reflect the contracted volumes and weighted average prices under the terms of the Company's derivative contracts as of December 31, 2022:

Swap Contracts

Production Period	Settlement Index	Average Daily Volumes	Weighted Average Swap Price
Crude oil:		*(Bbls)*	*(per Bbl)*
January 2023 – December 2023	NYMEX WTI CMA	17,863	$ 72.46
January 2024 – December 2024	NYMEX WTI CMA	5,240	$ 73.95
Natural gas:		*(MMBtu)*	*(per MMBtu)*
January 2023 – December 2023	NYMEX Henry Hub	26,395	$ 3.76
January 2024 – June 2024	NYMEX Henry Hub	10,000	$ 3.25

Collar Contracts

Production Period	Settlement Index	Average Daily Volumes	Weighted Average Put Price	Weighted Average Call Price
Crude oil:		*(Bbls)*	*(per Bbl)*	*(per Bbl)*
January 2023 – December 2023	NYMEX WTI CMA	2,512	$ 70.00	$ 86.59
January 2024 – March 2024	NYMEX WTI CMA	2,000	$ 70.00	$ 88.00
Natural gas:		*(MMBtu)*	*(per MMBtu)*	*(per MMBtu)*
January 2023 – December 2023	NYMEX Henry Hub	10,000	$ 5.25	$ 8.46
January 2024 – December 2024	NYMEX Henry Hub	10,000	$ 4.00	$ 6.90

The following tables provide additional information related to financial instruments measured at fair value on a recurring basis (in thousands):

	December 31, 2022			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas derivatives	$ —	$ 32,883	$ —	$ 32,883
Liabilities:				
Oil and natural gas derivatives	—	(76,242)	—	(76,242)
Total net liability	$ —	$ (43,359)	$ —	$ (43,359)

	December 31, 2021			
	Level 1	Level 2	Level 3	Total
Assets:				
Oil and natural gas derivatives	$ —	$ 3,737	$ —	$ 3,737
Liabilities:				
Oil and natural gas derivatives	—	(200,464)	—	(200,464)
Total net liability	$ —	$ (196,727)	$ —	$ (196,727)

Financial Statement Presentation

Derivatives are classified as either current or non-current assets or liabilities based on their anticipated settlement dates. Although the Company has master netting arrangements with its counterparties, the Company presents its derivative financial instruments on a gross basis in its Consolidated Balance Sheets. The following table presents the fair value of derivative financial instruments as well as the potential effect of netting arrangements on the Company's recognized derivative asset and liability amounts (in thousands):

	December 31, 2022		December 31, 2021	
	Assets	Liabilities	Assets	Liabilities
Oil and natural gas derivatives:				
Current	$ 25,029	$ 68,370	$ 967	$ 186,526
Non-current	7,854	7,872	2,770	13,938
Total gross amounts presented on balance sheet	32,883	76,242	3,737	200,464
Less: Gross amounts not offset on the balance sheet	32,883	32,883	3,737	3,737
Net amounts	$ —	$ 43,359	$ —	$ 196,727

Credit Risk

The Company is subject to the risk of loss on its financial instruments as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The Company has entered into International Swaps and Derivative Association agreements with counterparties to mitigate this risk. The Company also maintains credit policies with regard to its counterparties to minimize overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their creditworthiness; (ii) the regular monitoring of counterparties' credit exposures; (iii) the use of contract language that affords the Company netting or set off opportunities to mitigate exposure risk; and (iv) potentially requiring counterparties to post cash collateral, parent guarantees, or letters of credit to minimize credit risk. The Company's assets and liabilities from commodity price risk management activities at December 31, 2022 represent derivative instruments from eight counterparties; all of which are registered swap dealers that have an "investment grade" (minimum Standard & Poor's rating of BBB- or better) credit rating, and all of which are parties under the Company's Bank Credit Facility. The Company enters into derivatives directly with these counterparties and, subject to the terms of the Company's Bank Credit Facility, is not required to post collateral or other securities for credit risk in relation to the derivative activities.

Note 7 — Debt

A summary of the detail comprising the Company's debt and the related book values for the respective periods presented is as follows (in thousands):

	Year Ended December 31,	
	2022	2021
12.00% Second-Priority Senior Secured Notes – due January 2026	$ 638,541	$ 650,000
7.50% Senior Notes – due May 2022	—	6,060
Bank Credit Facility – matures November 2024	—	375,000
Total debt, before discount and deferred financing cost	638,541	1,031,060
Discount and deferred financing cost	(53,201)	(68,333)
Total debt, net of discount and deferred financing costs	585,340	962,727
Less: Current portion of long-term debt	—	6,060
Long-term debt, net of discount and deferred financing costs	$ 585,340	$ 956,667

12.00% Second-Priority Senior Secured Notes

The 12.00% Second-Priority Senior Secured Notes due 2026 (the "12.00% Notes") were issued pursuant to an indenture dated January 4, 2021 and the first supplemental indenture dated January 14, 2021 between the Parent Company (the "Parent Guarantor"), Talos Production Inc. (the "Issuer"), and certain of the Issuer's subsidiaries (the "Subsidiary Guarantors" and, together with the Parent Guarantor, the "Guarantors") and Wilmington Trust, National Association, as trustee and collateral agent. The 12.00% Notes rank pari passu in right of payment and constitute a single class of securities for all purposes under the indentures. The 12.00% Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by the Parent Guarantor and on a second-priority senior secured basis by each of the Subsidiary Guarantors and will be unconditionally guaranteed on the same basis by certain of the Issuer's future subsidiaries. The 12.00% Notes are secured on a second-priority basis by liens on substantially the same collateral as the Issuer's existing first-priority obligations under its Bank Credit Facility. The 12.00% Notes mature January 15, 2026 and have interest payable semi-annually each January 15 and July 15.

At any time prior to January 15, 2023, the Company may redeem up to 40% of the principal amount of the 12.00% Notes at a redemption rate of 112.00% of the principal amount plus accrued and unpaid interest. At any time prior to January 15, 2023, the Company may also redeem some or all of the 12.00% Notes at a price equal to 100% of the principal amount of the 12.00% Notes, plus a "make-whole premium," together with accrued and unpaid interest, if any, to, but excluding, the date of redemption. Thereafter, the Company may redeem all or a portion of the 12.00% Notes in whole at any time or in part from time to time at the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest if redeemed during the period commencing on January 15 of the years set forth below:

Period	Redemption Price
2023	106.00%
2024	103.00%
2025 and thereafter	100.00%

The indenture governing the 12.00% Notes applies certain limitations on the Company's ability and the ability of its subsidiaries to, among other things, (i) incur, assume or guarantee additional indebtedness or issue certain convertible or redeemable equity securities; (ii) create liens to secure indebtedness; (iii) pay distributions on equity interests, repurchase equity securities or redeem junior lien, unsecured or subordinated indebtedness; (iv) make investments; (v) restrict distributions, loans or other asset transfers from Talos Production Inc.'s restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of Talos Production Inc.'s properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates. The 12.00% Notes contain customary quarterly and annual reporting, financial and administrative covenants. The Company was in compliance with all debt covenants at December 31, 2022.

The Issuer initiated a notes consent solicitation on October 21, 2022, to obtain the requisite holders' consent to certain amendments to the indenture governing the Issuer's 12.00% Notes to permit the incurrence of indebtedness in respect of the 11.75% Senior Secured Second Lien Notes due 2026 of EnVen (the "Notes Consent Solicitation"). The Notes Consent Solicitation expired on October 27, 2022, with holders of 95.8% of the aggregate principal amount of the 12.00% Notes outstanding consenting. As a result, the Issuer entered into a second supplemental indenture to the base indenture on October 27, 2022, which became effective upon its execution. The Issuer offered holders of the 12.00% Notes consideration equal to 50 basis points times the principal amount of the 12.00% Notes held by such consenting holder ("Consent Fee").

During the year ended December 31, 2022, the Company repurchased $11.5 million of the 12.00% Notes. The debt repurchases resulted in a loss on extinguishment of debt for the year ended December 31, 2022 of $1.6 million, which is presented as "Other income (expense)" on the Consolidated Statements of Operations.

Subsequent Event — On February 13, 2023, the Issuer paid the Consent Fee of approximately $3.1 million in the aggregate in connection with the closing of the EnVen Acquisition.

11.00% Second-Priority Senior Secured Notes

On January 13, 2021, the Company redeemed $347.3 million aggregate principal amount of the 11.00% Second-Priority Senior Secured Notes due 2022 (the "11.00% Notes") at 102.75% plus accrued and unpaid interest using the proceeds from the issuance of the 12.00% Notes. The debt redemption resulted in a loss on extinguishment of debt of $13.2 million for the year ended December 31, 2021, which is included in "Other income (expense)" on the Consolidated Statements of Operations.

On June 15, 2020, the Company entered into an exchange agreement pursuant to which the Company agreed to exchange $37.2 million aggregate principal amount of the 11.00% Notes from certain holders in exchange for 3.1 million shares of the Company's common stock plus cash in an amount equal to accrued interest up to the June 18, 2020 settlement date. Additionally, during the year ended December 31, 2020, the Company repurchased $6.4 million of the 11.00% Notes. The exchange agreement and debt repurchases resulted in a gain on extinguishment of debt for the year ended December 31, 2020 of $1.7 million, which is included in "Other income (expense)" on the Consolidated Statements of Operations.

7.50% Senior Notes

On May 31, 2022, the 7.50% Senior Notes matured and were redeemed at an aggregate principal of $6.1 million plus accrued and unpaid interest.

Bank Credit Facility

The Company maintains a Bank Credit Facility with a syndicate of financial institutions. The Bank Credit Facility provides for the determination of the borrowing base based on the Company's proved producing reserves and a portion of the Company's proved undeveloped reserves. The borrowing base is redetermined by the lenders at least semi-annually during the second quarter and fourth quarter of each year. On May 4, 2022, the Company entered into a (i) Borrowing Base Redetermination Agreement and Eighth Amendment to Credit Agreement (the "Eighth Amendment") and (ii) Incremental Agreement of Increasing Lenders ("Incremental Agreement"). The Eighth Amendment and the Incremental Agreement, among other things, (i) increased the borrowing base from $950.0 million to $1.1 billion and (ii) increased the commitments from $791.3 million to $806.3 million. On December 23, 2022, the Company entered into the Incremental Agreement and Ninth Amendment to Credit Agreement (the "Ninth Amendment"). The Ninth Amendment, among other things, (i) extends the maturity date of the Bank Credit Facility from November 12, 2024 to March 31, 2027, (ii) increases the borrowing base from $1.1 billion to $1.5 billion and (iii) increases commitments from $806.3 million to $965.0 million, in each case contingent upon the closing of the EnVen Acquisition and the occurrence of certain events related thereto.

The Bank Credit Facility no longer bears interest at the applicable London InterBank Offered Rate plus the applicable margin. Interest under the Bank Credit Facility accrues at the Company’s option either at an alternate base rate (“ABR”) plus the applicable margin (“ABR Loans”), an adjusted term secured overnight financing rate (“SOFR”) plus the applicable margin (“Term Benchmark Loans”) or adjusted daily simple SOFR plus the applicable margin (“RFR Loans”). The ABR is based on the greater of (a) the prime rate, (b) a federal funds rate plus 0.5% or (c) the adjusted term SOFR for a one-month interest period plus 1.00%. The adjusted term SOFR is equal to the term SOFR for each applicable tenor (e.g., one-month, three-months, six-months, and twelve-months) calculated and published by the CME Group Inc. plus 0.10%. The adjusted daily simple SOFR is equal to the overnight SOFR calculated and published by the Federal Reserve Bank of New York plus 0.10%. In addition, the Company is obligated to pay a commitment fee on the unutilized portion of the commitments. The pricing grid below shows the applicable margin for Term Benchmark Loans, RFR Loans and ABR Loans as well as the commitment fee rate, in each case, prior to closing of the EnVen Acquisition, based upon the applicable borrowing base utilization percentage:

Borrowing Base Utilization Percentage	Utilization	Term Benchmark Loans and RFR Loans	ABR Loans	Commitment Fee Rate
Level 1	< 25%	3.00%	2.00%	0.50%
Level 2	≥ 25% < 50%	3.25%	2.25%	0.50%
Level 3	≥ 50% < 75%	3.50%	2.50%	0.50%
Level 4	≥ 75% < 90%	3.75%	2.75%	0.50%
Level 5	≥ 90%	4.00%	3.00%	0.50%

The Ninth Amendment provides that the above applicable margins for Term Benchmark Loans, RFR Loans and ABR Loans, each decrease by an amount equal to 0.25% from and after the closing of the EnVen Acquisition. The commitment fee rate also decreases to 0.375% from and after the closing of the EnVen Acquisition when the borrowing base utilization percentage is less than 50%.

The Bank Credit Facility has certain debt covenants, the most restrictive of which is that the Company must maintain a Consolidated Total Debt to EBITDAX Ratio (as defined in the Bank Credit Facility) of no greater than 3.00 to 1.00 calculated each quarter utilizing the most recent twelve months to determine EBITDAX. The Company must also maintain a current ratio no less than 1.00 to 1.00 each quarter. Under the Bank Credit Facility, unutilized commitments are included in current assets in the current ratio calculation. The Bank Credit Facility is secured by, among other things, mortgages covering at least 90.0% (or, from and after the closing of the EnVen Acquisition, 85.0%) of the oil and natural gas assets of the Company. The Bank Credit Facility is fully and unconditionally guaranteed by the Company and certain of its wholly-owned subsidiaries.

As of December 31, 2022, the Company's borrowing base was $1.1 billion with total commitments of $806.3 million. Additionally, no more than $200.0 million (or, from and after the closing of the EnVen Acquisition, $250.0 million) of the Company’s borrowing base can be used as letters of credit with current commitments at $150.0 million. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the Bank Credit Facility. The Company was in compliance with all debt covenants at December 31, 2022. See Note 12 — *Commitments and Contingencies* for the amount of letters of credit issued under the Bank Credit Facility as of December 31, 2022.

Subsequent Event — On February 10, 2023, the Company borrowed $130.0 million primarily used to fund the cash portion of the purchase price in the EnVen Acquisition. On February 13, 2023, as a result of the closing of the EnVen Acquisition, the borrowing base increased, commitments increased and the other changes all described above as contingent on the closing of the EnVen Acquisition went into effect. As of closing of the EnVen Acquisition, the Bank Credit Facility had approximately $754.2 million of undrawn commitments.

Limitation on Restricted Payments Including Dividends

The Company has not historically declared or paid any cash dividends on its capital stock. However, to the extent the Company determines in the future that it may be appropriate to pay a special dividend or initiate a quarterly dividend program, the Company's ability to pay any such dividends to its stockholders may be limited to the extent its consolidated subsidiaries are limited in their ability to make distributions to the Parent Company, including the significant restrictions that the agreements governing the Company's debt impose on the ability of its consolidated subsidiaries to make distributions and other payments to the Parent Company. With respect to entities accounted for under the equity method, the Company's primary equity method investee as of December 31, 2022 did not have any undistributed earnings.

The Bank Credit Facility contains restrictions on the ability of Talos Production Inc. to transfer funds to the Parent Company in the form of cash dividends, loans or advances. The Bank Credit Facility restricts distributions and other payments to the Parent Company, subject to certain baskets and other exceptions described therein including the payment of operating expense incurred in the ordinary course of business and for income taxes attributable to its ownership in Talos Production Inc. Under the Bank Credit Facility, general distributions and other restricted payments may be made to the Company so long as after giving pro forma effect to the making of any such restricted payment (i) no default or event of default has occurred and is continuing; (ii) available commitments exceed 25% of the then effective loan limit; (iii) the pro forma current ratio of 1.0 to 1.0 is satisfied; and (iv) either (A) the Consolidated Total Debt to EBITDAX Ratio (as defined in the Bank Credit Facility) is not greater than 1.75 to 1.00 and the aggregate amount of such restricted payments does not exceed the Available Free Cash Flow Amount (as defined in the Bank Credit Facility) at the time made or (B) the Consolidated Total Debt to EBITDAX Ratio is not greater than 1.00 to 1.00.

In addition, the indenture governing the 12.00% Notes restricts the Company's consolidated subsidiaries from, directly or indirectly, among other things, declaring or paying any dividend on account of their equity securities, subject to certain limited exceptions described in the indenture. Such exceptions include, among other things, if (i) no default has occurred or would occur as a result thereof, (ii) immediately after giving effect to such transaction on a pro forma basis, the issuer could incur $1.00 of additional indebtedness in compliance with a fixed charge coverage ratio of 2.25 to 1.00, (iii) the ratio of the issuer's total debt to EBITDA ratio is not greater than 3.00 to 1.00, and (iii) if payments pursuant to such transaction, together with the aggregate amount of certain other restricted payments, is less than the cumulative credit permitted under the indenture.

At December 31, 2022, restricted net assets of the Company's consolidated subsidiaries exceeded 25%.

Subsequent Event — EnVen Acquisition

On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the Company assumed EnVen's 11.75% Senior Secured Second Lien Notes due 2026 (the "EnVen Second Lien Notes") with a principal amount of $257.5 million. The EnVen Second Lien Notes mature on April 15, 2026 and interest accrues and is to be paid semi-annually in cash in arrears on April 15th and October 15th of each year. The indenture governing the EnVen Second Lien Notes requires the redemption of $15.0 million of the principal amount outstanding at par value on April 15th and October 15th of each year.

The EnVen Second Lien Notes are governed by an indenture by and among Energy Ventures GoM LLC, EnVen Finance Corporation as co-issuers, the guarantors party thereto and Wilmington Trust, National Association as trustee and collateral agent, dated as of April 15, 2021 ("EnVen Second Lien Notes Indenture"). Talos Production Inc. and certain of its subsidiaries entered into a supplemental indenture to the EnVen Second Lien Notes Indenture which, inter alia, provides for the assumption of the indebtedness in respect of the EnVen Second Lien Notes by Talos Production Inc., as well as guarantees of such indebtedness by certain subsidiaries of Talos Production Inc., as contemplated by the terms of the EnVen Second Lien Notes Indenture.

The EnVen Second Lien Notes Indenture contains certain covenants, which are customary with respect to non-investment grade debt securities, including limitations on the Company's ability to incur and guarantee additional indebtedness, repay, redeem, or repurchase certain debt and capital stock, issue certain preferred stock or similar equity securities, pay dividends or make other distributions on capital stock, enter into certain types of transactions with affiliates, make loans or investments, and make other restricted payments. Additionally, certain covenants restrict Talos Production Inc. subsidiaries' ability to pay dividends, create liens, and sell certain assets.

EnVen's reserve based loan facility, which had no borrowings as of February 13, 2023, was terminated at the time of the EnVen Acquisition.

Note 8 — Employee Benefits Plans and Share-Based Compensation

Long Term Incentive Plans

On May 11, 2021, the Company's stockholders approved the Talos Energy Inc. 2021 Long Term Incentive Plan (the "2021 LTIP"), which had previously been approved by the board of directors of the Company. No further awards will be granted under the Talos Energy Inc. Long Term Incentive Plan (the "2018 LTIP") (together with the 2021 LTIP, the "LTIP Plans").

The 2021 LTIP provides for potential grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws ("ISOs"), (ii) stock options that do not qualify as ISOs (together with ISOs, "Options"), (iii) stock appreciation rights, (iv) restricted stock awards, (v) RSUs, (vi) awards of vested stock, (vii) dividend equivalents, (viii) other share-based or cash awards and (ix) substitute awards. Employees, non-employee directors and consultants of the Company and its affiliates are eligible to receive awards under the 2021 LTIP. The 2021 LTIP authorizes the Company to grant awards of up to 8,639,415 shares of the Company's common stock, subject to the share counting and share recycling provisions of the 2021 LTIP.

Restricted Stock Units – Employees — RSUs granted to employees under the LTIP Plans primarily vest ratably over an approximate three year period subject to such employee's continued service through each vesting date. Upon vesting, each RSU represents a contingent right to receive one share of common stock. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2022 was approximately $24.6 million, which is expected to be recognized over a weighted average period of 1.7 years.

Restricted Stock Units – Non-employee Directors — RSUs granted to non-employee directors under the LTIP Plans vested approximately one year following the date of grant, subject to such non-employee director's continued service through the vesting date. Upon vesting, these RSUs represent a contingent right to receive one share of common stock for each RSU for 60%, and cash for the remaining 40%. The total unrecognized share-based compensation expense related to these RSUs at December 31, 2022 was approximately $0.2 million, which is expected to be recognized over a weighted average period of 0.2 years. Of the unrecognized share-based compensation expense, $0.1 million relates to liability awards and will be subsequently remeasured at each reporting period.

The following table summarizes RSU activity:

	Restricted Stock Units	Weighted Average Grant Date Fair Value
Unvested RSUs at December 31, 2019	733,777	$ 25.20
Granted	1,284,797	$ 10.02
Vested	(273,787)	$ 25.09
Forfeited	(91,799)	$ 19.65
Unvested RSUs at December 31, 2020	1,652,988	$ 13.73
Granted	1,102,038	$ 13.11
Vested	(669,832)	$ 15.01
Forfeited	(101,995)	$ 12.46
Unvested RSUs at December 31, 2021	1,983,199	$ 13.02
Granted	2,297,465	$ 13.23
Vested	(967,269)	$ 14.14
Forfeited	(97,891)	$ 14.34
Unvested RSUs at December 31, 2022(1)	3,215,504	$ 12.79

(1) As of December 31, 2022, 25,257 of the unvested RSUs were accounted for as liability awards in "Accrued liabilities" on the Consolidated Balance Sheet.

The Company considers its intent and ability to settle awards in cash or shares in determining whether to classify the awards as equity or as a liability. Certain awards granted during the year ended December 31, 2021 were originally classified as liability awards; however, these awards became equity-classified awards upon stockholder approval of the 2021 LTIP. The aggregate amount of compensation cost related to these awards is determined by the fair value of the award on the modification date.

Performance Share Units – Employees — PSUs granted to employees under the LTIP Plans represent the contingent right to receive one share of common stock. However, the number of shares of common stock issuable upon vesting ranges from zero to 200% of the target number of PSUs granted. The total unrecognized share-based compensation expense related to these PSUs at December 31, 2022 was approximately $14.0 million, which is expected to be recognized over a weighted average period of 1.8 years.

The following table summarizes PSU activity:

	Performance Share Units	Weighted Average Grant Date Fair Value
Unvested PSUs at December 31, 2019	417,831	$ 39.31
Granted	441,642	$ 13.05
Forfeited	(25,301)	$ 37.67
Unvested PSUs at December 31, 2020	834,172	$ 25.46
Granted	586,995	$ 18.96
Vested	(391,308)	$ 39.43
Forfeited	(14,400)	$ 18.48
Unvested PSUs at December 31, 2021	1,015,459	$ 16.41
Granted(1)	629,666	$ 23.73
Vested(2)	(14,474)	$ 13.05
Forfeited	(16,486)	$ 17.48
Cancelled	(975,564)	$ 16.42
Unvested PSUs at December 31, 2022	638,601	$ 23.66

(1) There were 314,833 PSUs granted that are eligible to vest based on continued employment and the Company's annualized absolute total shareholder return ("TSR") over a three-year performance period. An additional 314,833 PSUs were granted and are eligible to vest based on continued employment and the Company's return on the wells included in the 2022 drill program over a three-year performance period.

(2) The performance period for the relative TSR awards ended on December 31, 2022. The payout on these awards was 0% based on actual performance over the performance period as certified by the Compensation Committee of the Company's Board of Directors in early 2023. Since these awards were legally forfeited they will again be available for new awards under the recycling provisions of the 2021 LTIP.

Certain awards granted during the year ended December 31, 2021 were originally classified as liability awards; however, these awards became equity-classified awards upon stockholder approval of the 2021 LTIP. The following table summarizes the assumptions used in the Monte Carlo simulations to calculate the fair value of the relative or absolute TSR PSUs granted and modified at the date indicated:

	2022		2021		2020
	Grant	Grant	Modification	Grant	Grant
	September 20	March 5	May 11	March 8	March 5
Expected term (in years)	2.3	2.8	2.6	2.8	2.8
Expected volatility	74.3%	82.2%	80.9%	78.3%	48.8%
Risk-free interest rate	3.9%	1.6%	0.3%	0.3%	0.6%
Dividend yield	—%	—%	—%	—%	—%
Fair value (in thousands)	$ 621	$ 8,668	$ 9,715	$ 11,129	$ 5,763

Modification — During March 2022, the outstanding PSUs held by certain executive officers that were awarded in 2020 and 2021 were cancelled and, in connection with this cancellation, 1,147,352 of RSUs were granted (the "Retention RSUs"). The Retention RSUs will vest ratably each year over two years, generally contingent upon continued employment through each such date. The cancellation of the PSUs along with the concurrent grant of the Retention RSUs are accounted for as a modification. The incremental cost of $9.7 million will be recognized prospectively over the modified requisite service period. Additionally, the remaining unrecognized grant or modification date fair value of the original PSUs will be recognized over the original remaining requisite service period.

Share-based Compensation Costs

Share-based compensation costs associated with RSUs, PSUs and other awards are reflected as "General and administrative expense" on the Consolidated Statements of Operations, net amounts capitalized to "Proved Properties" on the Consolidated Balance Sheets. Because of the non-cash nature of share-based compensation, the expensed portion of share-based compensation is added back to net income in arriving at "Net cash provided by operating activities" on the Consolidated Statements of Cash Flows.

The following table presents the amount of costs expensed and capitalized (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Share-based compensation costs	$ 28,280	$ 20,560	$ 16,462
Less: Amounts capitalized to oil and gas properties	12,327	9,568	7,793
Total share-based compensation expense	$ 15,953	$ 10,992	$ 8,669

Note 9 — Income Taxes

Income Tax Expense (Benefit)

The components of income tax expense (benefit) were as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Current income tax expense (benefit):			
United States	$ 1,375	$ (5)	$ (499)
Mexico	432	(993)	185
Total current income tax expense (benefit)	$ 1,807	$ (998)	$ (314)
Deferred income tax expense (benefit):			
United States	$ 659	$ (1,067)	$ 35,923
Mexico	71	430	(26)
Total deferred income tax expense (benefit)	$ 730	$ (637)	$ 35,897
Total income tax expense (benefit)	$ 2,537	$ (1,635)	$ 35,583

A reconciliation of income tax expense (benefit) computed at the U.S. federal statutory tax rate to the Company's income tax expense (benefit) is as follows (in thousands, except percentages):

	Year Ended December 31,		
	2022	2021	2020
Income tax expense (benefit) at the federal statutory tax rate	$ 80,735	$ (38,763)	$ (90,304)
State income taxes	1,591	(674)	(14,215)
Impact of foreign operations	15,657	(11,920)	(1,030)
Effect of change in state rate	—	2,008	—
Prior year taxes	(2,920)	486	(4,237)
Legal entity reorganization	—	—	(17,566)
Change in valuation allowance	(96,537)	45,547	162,213
Other permanent differences	4,011	1,681	722
Total income tax expense (benefit)	$ 2,537	$ (1,635)	$ 35,583
Effective tax rate	0.66%	0.89%	(8.27)%

The Company's effective tax rate for the years ended December 31, 2022 and 2021 differed from the federal statutory rate of 21.0% primarily due to recording a full valuation allowance against its federal, state and foreign deferred tax assets.

The Company's effective tax rate for the year ending December 31, 2020 differed from the federal statutory rate of 21.0% primarily due to a non-cash tax expense of $162.2 million related to the recognition of a valuation allowance for its excess federal and state deferred tax assets. This expense was partially offset by a tax benefit of $17.6 million from adopting the final Treasury Regulations under Section 163(j) of the Internal Revenue Code (the "IRC") for tax years ended December 31, 2018 and December 31, 2019. The adoption of the final Treasury Regulations reduced the non-cash tax expense recognized in the year ending December 31, 2019 from the legal entity conversion of a partnership to a corporation.

Deferred Tax Assets and Liabilities

Net deferred tax assets (liabilities) reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of deferred tax assets and liabilities were as follows (in thousands):

	Year Ended December 31, 2022	Year Ended December 31, 2021
Deferred tax assets:		
Federal net operating loss	$ 159,257	$ 153,849
Foreign tax loss carryforward	44,462	49,932
State net operating loss	24,787	24,265
Tax credits	107	303
Interest expense carryforward	23,262	—
Asset retirement obligations	115,848	92,823
Derivatives	9,273	42,075
Other well equipment inventory	1,891	5,680
Accrued bonus	5,863	5,087
Share-based compensation	5,296	3,833
Operating lease liabilities	3,669	4,081
Finance lease liabilities	32,559	—
Other	7,142	5,424
Total deferred tax assets	433,416	387,352
Valuation allowance	(129,105)	(224,266)
Total deferred tax assets, net	$ 304,311	$ 163,086
Deferred tax liabilities:		
Oil and gas properties	$ 302,602	$ 160,002
Operating lease assets	1,323	1,423
Prepaid	2,530	3,075
Total deferred tax liabilities	306,455	164,500
Net deferred tax liability	$ (2,144)	$ (1,414)

Net Operating Loss

The table below presents the details of the Company's net operating loss carryovers as of December 31, 2022 (in thousands):

	Amount	Expiration Year
Federal net operating losses	$ 525,745	2035 - 2037
Federal net operating losses	$ 232,620	Unlimited
Foreign tax loss carryforward	$ 148,206	2025 - 2032
State net operating losses	$ 125,958	2025 - 2037
State net operating losses	$ 277,031	Unlimited

As of December 31, 2022, the Company had U.S. federal net operating loss carryforwards ("NOLs") of approximately $758.4 million, all of which is subject to limitation under Section 382 of the IRC. IRC Section 382 provides an annual limitation with respect to the ability of a corporation to utilize its tax attributes, against future U.S. taxable income in the event of a change in ownership. If not utilized, such carryforwards would begin to expire at the end of 2035.

Valuation Allowance

The Company recorded a valuation allowance of $129.1 million and $224.3 million as of December 31, 2022 and 2021, respectively. Deferred income tax assets and liabilities are recorded related to NOLs and temporary differences between the book and tax basis of assets and liabilities expected to produce tax deductions and income in the future. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions in which those temporary differences or NOLs relate.

In assessing the need for a valuation allowance, the Company considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized using available positive and negative evidence, including future reversals of temporary differences, tax-planning strategies and future taxable income, to estimate whether sufficient future taxable income will be generated to permit use of deferred tax assets. A significant piece of objective negative evidence evaluated is the cumulative loss incurred over recent years. Such objective negative evidence limits our ability to consider other subjective positive evidence.

The Company intends to continue maintaining a full valuation allowance on our deferred tax assets until there is sufficient evidence to support the reversal of all or some portion of these allowances. However, if positive earnings continue to be realized and future earnings are anticipated, the Company believes that there is a reasonable possibility that within the next 12 months, sufficient positive evidence may become available to allow us to reach a conclusion that a significant portion of the valuation allowance will no longer be needed. Release of the valuation allowance would result in the recognition of certain deferred tax assets and a decrease to income tax expense for the period the release is recorded. However, the exact timing and amount of the valuation allowance release are subject to change on the basis of the level of profitability that the Company achieves and anticipates realizing in future years.

Uncertain Tax Positions

The table below sets forth the beginning and ending balance of the total amount of unrecognized tax benefits. None of the unrecognized benefits would impact the effective tax rate if recognized. While amounts could change during the next 12 months, the Company does not anticipate having a material impact on its financial statements.

Balances in the uncertain tax positions are as follows (in thousands):

	Year Ended December 31,	
	2022	2021
Total unrecognized tax benefits, beginning balance	$ 696	$ 648
Increases in unrecognized tax benefits as a result of:		
Tax positions taken during a prior period	100	21
Tax positions taken during the current period	39	27
Total unrecognized tax benefits, ending balance	$ 835	$ 696

The Company recognizes interest and penalties related to uncertain tax positions as “Interest Expense” and “General and administrative expense” on the Consolidated Statements of Operations, respectively.

Years Open to Examination

The 2019 through 2021 tax years remain open to examination by the tax jurisdictions in which the Company is subject to tax. The statute of limitations with respect to the U.S. federal income tax returns of the Company for years ending on or before December 31, 2018 are closed, except to the extent of any NOL carryover balance.

Note 10 — Income (Loss) Per Share

Basic earnings per common share is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of shares of common stock outstanding during the period. Except when the effect would be antidilutive, diluted earnings per common share includes the impact of RSUs, PSUs and outstanding warrants. The warrants expired unexercised on February 28, 2021.

The following table presents the computation of the Company's basic and diluted income (loss) per share were as follows (in thousands, except for the per share amounts):

	Year Ended December 31,		
	2022	2021	2020
Net income (loss)	$ 381,915	$ (182,952)	$ (465,605)
Weighted average common shares outstanding — basic	82,454	81,769	67,664
Dilutive effect of securities	1,229	—	—
Weighted average common shares outstanding — diluted	83,683	81,769	67,664
Net income (loss) per common share:			
Basic	$ 4.63	$ (2.24)	$ (6.88)
Diluted	$ 4.56	$ (2.24)	$ (6.88)
Anti-dilutive potentially issuable securities excluded from diluted common shares	865	1,709	5,019

Note 11 — Related Party Transactions

Apollo Funds and Riverstone Funds

On February 3, 2012, Talos Energy LLC completed a transaction with funds and other alternative investment vehicles managed by Apollo Management VII, L.P. and Apollo Commodities Management, L.P., with respect to Series I ("Apollo Funds"), and entities controlled by or affiliated with Riverstone Energy Partners V, L.P. ("Riverstone Funds" and together with the Apollo Funds, the "Sponsors") and members of management pursuant to which the Company received a private equity capital commitment. On January 3, 2022, the Apollo Funds ceased being a beneficial owner of more than five percent of the Company's common stock. Riverstone Funds held 14.9% of the Company's common stock as of December 31, 2022.

ILX and Castex Acquisition

On February 28, 2020 the Company acquired assets and liabilities at fair value from sellers that include, the Riverstone Sellers, affiliates of the Riverstone Funds. See additional details in Note 3 — *Acquisitions.*

Whistler Acquisition

On August 31, 2018, the Company acquired Whistler Energy II, LLC from Whistler Energy II Holdco, LLC, an affiliate of the Apollo Funds. A settlement agreement related to a dispute regarding the decommissioning obligation of a Deepwater well was executed in September 2021. For the year ended December 31, 2021, the Company recognized a $4.4 million gain resulting from the settlement which is reflected in "Other income (expense)" on the Company's Consolidated Statements of Operations.

Registration Rights Agreements

On May 10, 2018, the Company entered into a Registration Rights Agreement (the "Original Equity Registration Rights Agreement") with certain of the Apollo Funds and the Riverstone Funds, certain funds controlled by Franklin Advisers, Inc. ("Franklin") and certain clients of MacKay Shields LLC ("MacKay Shields"), relating to the registered resale of the Company's common stock owned by such parties as of the closing of the Stone Combination (the "Original Registrable Securities").

The Company and the Riverstone Sellers (and their designated affiliates) agreed under the Purchase Agreements to enter into an amendment to the Original Equity Registration Rights Agreement (such amendment, the "Registration Rights Agreement Amendment," and the Original Equity Registration Rights Agreement, as amended by the Registration Rights Agreement Amendment, the "Registration Rights Agreement"). The Registration Rights Agreement Amendment will add each of the Riverstone Sellers (or one or more of its designated affiliates) as parties to the Registration Rights Agreement and provide such parties with customary registration rights with respect to the Series A Convertible Preferred Stock (and Conversion Stock) (each as defined below) that the Riverstone Sellers received at the closing of the ILX and Castex Acquisition (the "New Registrable Securities" and together with the Original Registrable Securities, the "Registrable Securities"). Under the Registration Rights Agreement, the Company is required to file a shelf registration statement within 30 days of the Company's receipt of written request by a holder of Registrable Securities (a "Holder"). Each Holder will be limited to two demand registrations in any twelve-month period.

The Holders have the right to request that the Company initiate underwritten offerings of the Company's common stock; provided, that the Apollo Funds and the Riverstone Funds will have the right to demand three underwritten offerings in any twelve-month period, and Franklin and MacKay Shields will only have the collective right to demand one underwritten offering. The Holders have customary piggyback rights with respect to any underwritten offering that the Company conducts for as long as the Holders and their respective affiliates own 5% of the Registrable Securities. Each Holder will agree to a lock up with underwriters in the event of an underwritten offering, provided that the lock up will not apply to any Holder who does not have a right to participate in such underwritten offering. The Registration Rights Agreement have terminated with respect to Franklin and MacKay Shields. Additionally, the Apollo Funds no longer have piggyback rights effective January 3, 2022. The Registration Rights Agreement will otherwise terminate at such time as there are no Registrable Securities outstanding.

In connection with the closing of the ILX and Castex Acquisition, and pursuant to the Purchase Agreements, as amended, the Company and ILX Holdings, LLC, ILX Holdings II, LLC, ILX Holdings III LLC and Riverstone V Castex 2014 Holdings, L.P., a Delaware limited partnership and designee of Castex Energy 2014, LLC, entered into the Registration Rights Agreement Amendment to the Registration Rights Agreement to, among other things, add each of the Riverstone Sellers (or one or more of its designated affiliates) as parties to the Registration Rights Agreement and provide such parties with customary registration rights with respect to the Company's Series A Convertible Preferred Stock issued to the Riverstone Sellers at the closing of the ILX and Castex Acquisition

The Company will bear all of the expenses incurred in connection with any offer and sale, while the selling stockholders will be responsible for paying underwriting fees, discounts and selling commissions. The Company incurred fees of nil, $0.7 million and $0.2 million for the fiscal years ended December 31, 2022, 2021 and 2020, respectively.

In June and November of 2021, the Company entered into separate secondary underwriting agreements with certain stockholders affiliated with the Sponsors (the "Selling Stockholders"), pursuant to which the Selling Stockholders sold shares of common stock of the Company. Each secondary offering was made pursuant to a prospectus supplement filed with the SEC. The Selling Stockholders received all the proceeds from these offerings.

In connection with the Company's entry into the EnVen Merger Agreement on September 21, 2022 to acquire EnVen, the Company entered into a registration rights agreement (the "2022 Registration Rights Agreement") with Adage Capital Partners, L.P. ("Adage") and affiliated entities of Bain Capital, LP ("Bain"). Pursuant to the 2022 Registration Rights Agreement, the Company grants to Adage and Bain certain demand, "piggy-back" and shelf registration rights with respect to the shares of the Company's common stock to be received by such entities in the EnVen Acquisition, subject to certain customary thresholds and conditions. Additionally, the Company agrees to pay certain expenses of the parties incurred in connection with the exercise of their rights under such agreement and to indemnify them for certain securities law matters in connection with any registration statement filed pursuant thereto. The 2022 Registration Rights Agreement will become effective at the closing of the EnVen Acquisition.

Subsequent Event — On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the 2022 Registration Rights Agreement became effective. Adage and Bain hold approximately 5.1% and 12.3%, respectively, of the Company's outstanding shares of common stock.

Amended and Restated Stockholders' Agreement

On May 10, 2018, the Company entered into a Stockholders' Agreement (the "Stockholders' Agreement") by and among the Company and the other parties thereto. On February 24, 2020, the Company and the other parties thereto amended the Stockholders' Agreement to, among other things, add each of the Riverstone Sellers (or one or more of its designated affiliates) as parties to the Stockholders' Agreement and provide that for purposes of determining whether the Riverstone Sellers and their affiliates continue to satisfy certain stock ownership requirements necessary to retain their rights to nominate directors to the board of directors, the Series A Convertible Preferred Stock owned by the Riverstone Sellers was, prior to the conversion thereof, counted towards such ownership requirements on an as converted basis at the closing of the ILX and Castex Acquisition. On March 30, 2020, all 110,000 shares of Series A Convertible Preferred Stock were converted into an aggregate 11.0 million shares of the Company's common stock.

On March 29, 2022, the Company and other parties thereto, entered into the Amended and Restated Stockholders' Agreement, in connection with the resignation of certain members of the Company's Board of Directors (the "Amended and Restated Stockholders' Agreement"). The Amended and Restated Stockholders' Agreement, among other things, (i) terminates the rights of the Apollo Funds under the Stockholders' Agreement and (ii) eliminates the requirement that the Board of Directors consist of ten members.

The Riverstone Funds have agreed to vote their shares of the Company's common stock in favor of any nominee designated and nominated for election to the Board of Directors in accordance with the terms of the Amended and Restated Stockholders' Agreement and in a manner consistent with the recommendation of the Nominating and Governance Committee with respect to all other nominees.

In connection with the pending EnVen Acquisition, the Company and the Riverstone Funds have agreed to terminate the Amended and Restated Stockholders' Agreement, which will eliminate the Riverstone Funds' designation rights with respect to the Company's Board of Directors. Subsequent to the termination of the Amended and Restated Stockholders' Agreement, the Riverstone Funds' present designee to the Company's Board of Directors, Mr. Robert M. Tichio, will immediately tender his resignation. The termination of the Amended and Restated Stockholders' Agreement is contingent upon the successful closing of the EnVen Acquisition.

Subsequent Event — On February 13, 2023, in conjunction with the closing of the EnVen Acquisition, the Amended and Restated Stockholders' Agreement was terminated and Mr. Robert M. Tichio resigned from the Company's Board of Directors.

Riverstone Support Agreement

In connection with the pending EnVen Acquisition, the Company, EnVen and the Riverstone Funds entered into a support agreement pursuant to which the Riverstone Funds have agreed, among other things, to (i) vote all shares of Company common stock beneficially owned (a) in favor of the share issuance to EnVen equityholders, (b) in favor of the amendment and/or restatement of the Company's organizational documents as necessary or appropriate to reflect the termination of the Amended and Restated Stockholders' Agreement, (c) in favor of any other proposals necessary or appropriate in connection with the EnVen Acquisition and (d) against, among other things, (A) any Acquisition Proposal (as defined in the EnVen Merger Agreement) with respect to the Company and (B) any other proposal that could reasonably be expected to materially impede or delay the EnVen Acquisition or result in a breach of any representation or covenant of the Company under the EnVen Merger Agreement (as defined herein), (ii) terminate the Amended and Restated Stockholders' Agreement, and (iii) cause Mr. Tichio to resign from the Company's Board of Directors, in each case of the foregoing clauses (ii) and (iii), effective immediately prior to, but conditioned on, the occurrence of the closing of the EnVen Acquisition.

Legal Fees

The Company has engaged the law firm Vinson & Elkins L.L.P. ("V&E") to provide legal services. An immediate family member of William S. Moss III, the Company's Executive Vice President and General Counsel and one of its executive officers, is a partner at V&E. For the years ended December 31, 2022, 2021 and 2020, the Company incurred fees of approximately $4.8 million, $3.1 million and $3.5 million, respectively, of which $1.3 million, $0.2 million and $0.7 million were payable at each respective balance sheet date for legal services performed by V&E.

Bayou Bend CCS LLC

On March 8, 2022, the Company made a $2.3 million cash contribution for a 50% membership interest in Bayou Bend. On May 24, 2022, the Company sold a 25% membership interest to Chevron U.S.A. Inc. ("Chevron") for upfront cash consideration of $15.0 million. Chevron also agreed to fund up to $10.0 million of contributions to Bayou Bend on the Company's behalf, of which $1.4 million was funded during the year ended December 31, 2022. The Bayou Bend investment will be increased with an offsetting gain as the capital carry is funded by Chevron. The Company recognized a $15.3 million gain on the partial sale of its investment in Bayou Bend during the year ended December 31, 2022, which is included in "Equity method investment income" on the Consolidated Statements of Operations.

As of December 31, 2022, the Company owns a 25% membership interest in Bayou Bend, which is a variable interest entity and accounted for using the equity method of accounting. Bayou Bend has a CCS site located offshore Jefferson County, Texas, near the Beaumont and Port Arthur, Texas industrial corridor that is in the early stages of development. The development of the Bayou Bend CCS hub project is currently being financed through equity contributions from its members. The Company's maximum exposure to loss as result of its involvement with Bayou Bend is the carrying amount of its investment.

Under an operating agreement, which was amended on May 24, 2022, the Company has agreed to provide certain services to facilitate Bayou Bend's operations and to fulfill other general and administrative functions relating to the operation and management of Bayou Bend and its business. The Company will invoice Bayou Bend for reimbursement of direct and indirect general and administrative expenses incurred as well as all other direct out-of-pocket costs and expenses incurred or paid on behalf of Bayou Bend. The Company had a $0.7 million related party receivable from Bayou Bend as of December 31, 2022.

Note 12 — Commitments and Contingencies

Legal Proceedings and Other Contingencies

From time to time, the Company is involved in litigation, regulatory examinations and administrative proceedings primarily arising in the ordinary course of business in jurisdictions in which the Company does business. Although the outcome of these matters cannot be predicted with certainty, the Company's management believes none of these matters, either individually or in the aggregate, would have a material effect upon the Company's financial position; however, an unfavorable outcome could have a material adverse effect on the Company's results from operations for a specific interim period or year.

On March 23, 2022, the Company entered into a settlement agreement to receive $27.5 million to resolve previously pending litigation, which was filed on October 23, 2017, against a third-party supplier related to quality issues. As part of the settlement agreement, the Company released all of its claims in the litigation. The settlement is reflected as "Other income (expense)" on the Consolidated Statements of Operations.

Performance Obligations

Regulations with respect to the Company's operations govern, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells, removal of facilities in the U.S. Gulf of Mexico and certain obligations under the production sharing contracts with Mexico.

As of December 31, 2022, the Company had secured performance bonds from third party sureties totaling $740.6 million. The cost of securing these bonds is reflected as "Interest expense" on the Consolidated Statements of Operations. Additionally, as of December 31, 2022, the Company had secured letters of credit issued under its Bank Credit Facility totaling $3.9 million. Letters of credit that are outstanding reduce the available revolving credit commitments. See Note 7 — *Debt* for further information on the Bank Credit Facility.

The table below summarizes the Company's total minimum commitments associated with vessel commitments, purchase obligations and other miscellaneous commitments as of December 31, 2022 (in thousands):

	2023	2024	2025	2026	Thereafter	Total
Vessel Commitments[1]	$ 41,938	$ —	$ —	$ —	$ —	$ 41,938
Committed purchase orders[2]	41,148	—	—	—	—	41,148
EnVen Acquisition[3]	259,858	—	—	—	—	259,858
Other commitments[4]	9,627	327	327	—	—	10,281
Total	$ 352,571	$ 327	$ 327	$ —	$ —	$ 353,225

(1) Includes vessel commitments the Company will utilize for certain Deepwater well intervention, drilling operations and decommissioning activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will be billed for their working interest share of such costs.

(2) Includes committed purchase orders to execute planned future drilling activities. These commitments represent gross contractual obligations and accordingly, other joint owners in the properties operated by the Company will be billed for their working interest share of such costs.

(3) Includes cash consideration and contingent fees related to the EnVen Acquisition. See Note 15 — *Subsequent Events* for further information on the EnVen Acquisition.

(4) Includes commitment to acquire additional lease acreage associated with our CCS Segment.

Decommissioning Obligations

The Company has divested various leases, wells and facilities located in the U.S. Gulf of Mexico where the purchasers typically assume all abandonment obligations acquired. Certain of these counterparties in these divestiture transactions or third parties in existing leases have filed for bankruptcy protection or undergone associated reorganizations and may not be able to perform required abandonment obligations. Under certain circumstances, regulations or federal laws could require the Company to assume such obligations. The Company reflects expenses incurred related to estimated decommissioning obligations in "Other operating (income) expense" on the Consolidated Statements of Operations.

The decommissioning obligations included in the Consolidated Balance Sheets as "Other current liabilities" and "Other long-term liabilities", and the changes in that liability were as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Balance, beginning of period	$ 24,336	$ —	$ —
Additions	8,900	21,056	—
Changes in estimate	22,658	—	—
Reimbursements due from third parties	—	3,280	—
Settlements	(1,625)	—	—
Balance, end of period	$ 54,269	$ 24,336	$ —
Less: Current portion	42,069	3,756	—
Long-term portion	$ 12,200	$ 20,580	$ —

Although it is reasonably possible that the Company could receive state or federal decommissioning orders in the future or be notified of defaulting third parties in existing leases, the Company cannot predict with certainty, if, how or when such orders or notices will be resolved or estimate a possible loss or range of loss that may result from such orders. However, the Company could incur judgments, enter into settlements or revise our opinion regarding the outcome of certain notices or matters, and such developments could have a material adverse effect on our results of operations in the period in which the amounts are accrued and our cash flows in the period in which the amounts are paid.

Note 13 — Segment Information

The Company's operations are managed through two operating segments: (i) Upstream Segment and (ii) CCS Segment. The Upstream Segment is the Company's only reportable segment. The Company's chief operating decision-maker ("CODM") is the President and Chief Executive Officer, who reviews operating results to make decisions about allocating resources and assessing performance for the entire company. The profit or loss metric used to evaluate segment performance is Adjusted EBITDA, which is defined as net income (loss) plus interest expense; income tax expense (benefit); depreciation, depletion, and amortization; accretion expense; non-cash write-down of oil and natural gas properties; transaction and other (income) expenses; decommissioning obligations; the net change in the fair value of derivatives (mark to market effect, net of cash settlements and premiums related to these derivatives); (gain) loss on debt extinguishment; non-cash write-down of other well equipment inventory; and non-cash equity-based compensation expense.

Corporate general and administrative expense include certain shared costs such as finance, accounting, tax, human resources, information technology and legal costs that are not directly attributable to each of operating segment. A portion of these expenses are allocated based on the percentage of employees dedicated to each operating segment. The remaining expenses are included in the reconciliation of reportable segment Adjusted EBITDA to consolidated pre-tax net income (loss) as an unallocated corporate general and adminsitrative expense. The accounting policies of the segments are the same as those described in the summary of significant accounting policies.

The Company's CODM does not review assets by segment as part of the financial information provided and therefore, no asset information is provided in the table below.

The following table presents selected segment information for the periods indicated (in thousands):

	Upstream	All Other[(1)]	Total
Revenues from External Customers:			
Year Ended December 31, 2022	$ 1,651,980	$ —	$ 1,651,980
Year Ended December 31, 2021	1,244,540	—	1,244,540
Year Ended December 31, 2020	575,936	—	575,936
Equity in the Net Income of Investees Accounted for by the Equity Method:			
Year Ended December 31, 2022	$ 101	$ (1,166)	$ (1,065)
Year Ended December 31, 2021	—	—	—
Year Ended December 31, 2020	—	—	—
Adjusted EBITDA:			
Year Ended December 31, 2022	$ 859,840	$ (12,786)	$ 847,054
Year Ended December 31, 2021	$ 615,798	$ (4,782)	611,016
Year Ended December 31, 2020	435,327	—	435,327
Segment Expenditures:			
Year Ended December 31, 2022	$ 452,674	$ 2,778	$ 455,452
Year Ended December 31, 2021	338,822	—	338,822
Year Ended December 31, 2020	405,525	—	405,525

(1) The CCS Segment is included in the "All Other" category. The CCS Segment is an emerging business in the start-up phase of operations and the business that does not currently generate any revenues. The CCS Segment's business activities are conducted through both wholly owned subsidiaries and equity method investments with industry partners. Equity method investments is a business strategy that enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed.

Reconciliations

The following tables present reconciliations of reportable segment information to the Company's consolidated totals (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Adjusted EBITDA:			
Total for reportable segments	$ 859,840	$ 615,798	$ 435,327
All other	(12,786)	(4,782)	—
Unallocated corporate general and administrative expense	(5,280)	(4,542)	(5,088)
Interest expense	(125,498)	(133,138)	(99,415)
Depreciation, depletion and amortization	(414,630)	(395,994)	(364,346)
Accretion expense	(55,995)	(58,129)	(49,741)
Write-down of oil and natural gas properties	—	(18,123)	(267,916)
Transaction and other (income) expenses[(1)]	34,513	(5,886)	(14,917)
Decommissioning obligations[(2)]	(31,558)	(21,055)	—
Derivative fair value loss (gain) [(3)]	(272,191)	(419,077)	87,685
Net cash paid on settled derivative instruments [(3)]	425,559	290,164	(143,905)
Gain (loss) on extinguishment of debt	(1,569)	(13,225)	1,662
Non-cash write-down of other well equipment inventory	—	(5,606)	(699)
Non-cash equity-based compensation expense	(15,953)	(10,992)	(8,669)
Income (loss) before income taxes	$ 384,452	$ (184,587)	$ (430,022)

(1) Other income (expense) includes restructuring expenses, cost saving initiatives and other miscellaneous income and expenses that we do not view as a meaningful indicator of our operating performance. For the year ended December 31, 2022, the amount includes $27.5 million gain as a result of the settlement agreement to resolve previously pending litigation that was filed in October 2017 that is further discussed in Note 12 — *Commitments and Contingencies.* Additionally, it includes a $15.3 million gain for the year ended December 31, 2022 on partial sale of our investment in Bayou Bend that is further discussed in Note 11 — *Related Party Transactions*. For the year ended December 31, 2020, the amount includes $1.4 million of legal entity restructuring costs and $1.3 million of severance related cost saving initiatives due to the COVID-19 pandemic.

(2) Estimated decommissioning obligations were a result of working interest partners or counterparties of divestiture transactions that were unable to perform the required abandonment obligations due to bankruptcy or insolvency. See Note 12 — *Commitments and Contingencies* for additional information on decommissioning obligations.

(3) The adjustments for the derivative fair value (gains) losses and net cash receipts (payments) on settled commodity derivative instruments have the effect of adjusting net loss for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDA on an unrealized basis during the period the derivatives settled.

	Year Ended December 31,		
	2022	2021	2020
Segment Expenditures:			
Total reportable segments	$ 452,674	$ 338,822	$ 405,525
All other	2,778	—	—
Change in capital expenditures included in accounts payable and accrued liabilities	(60,011)	28,258	16,002
Plugging & abandonment	(69,596)	(67,988)	(43,933)
Decommissioning obligations settled	(1,625)	—	—
Investment in CCS intangibles and equity method investees	(2,778)	—	—
Other deferred payments	—	(7,921)	(11,921)
Non-cash well equipment inventory transfers	(6)	1,086	(3,030)
Other	1,728	1,074	299
Exploration, development and other capital expenditures	$ 323,164	$ 293,331	$ 362,942

Note 14 — Supplemental Oil and Gas Disclosures (Unaudited)

Capitalized Costs

Aggregate amounts of capitalized costs relating to oil, natural gas and NGL activities and the aggregate amount of related accumulated depletion and amortization as of the dates indicated are presented below (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Proved properties	$ 5,964,340	$ 5,232,479	$ 4,945,550
Unproved oil and gas properties, not subject to amortization(1)	154,783	219,055	254,994
Total oil and gas properties	6,119,123	5,451,534	5,200,544
Less: Accumulated depletion	3,484,590	3,072,907	2,680,254
Net capitalized costs	$ 2,634,533	$ 2,378,627	$ 2,520,290
Depletion and amortization rate (Per MBoe)(2)	$ 18.95	$ 16.71	$ 31.42

(1) Amount includes $111.4 million, $110.3 million and $121.7 million of unproved properties, not subject to amortization, related to the Company's operations in offshore Mexico for the years ended December 31, 2022, 2021 and 2020, respectively.

(2) Year ended December 31, 2020 includes the impact of a write-down of U.S. oil and natural gas properties as a result of the Company's ceiling test computations. See Note 4 — *Property, Plant and Equipment* for additional information.

Included in the depletable basis of proved oil and gas properties is the estimate of the Company's proportionate share of asset retirement costs relating to these properties which are also reflected as "Asset retirement obligations" on the accompanying Consolidated Balance Sheets. See Note 4 — *Property, Plant and Equipment* for additional information.

Costs Incurred for Property Acquisition, Exploration and Development Activities

The following table reflects the costs incurred in oil, natural gas and NGL property acquisition, exploration and development activities during the years indicated (in thousands). Costs incurred also include new asset retirement obligations established in the current year, as well as increases or decreases to the asset retirement obligations resulting from changes to estimates during the year.

	Year Ended December 31,		
	2022	2021	2020
Property acquisition costs:			
Proved properties	$ —	$ 210	$ 422,833
Unproved properties, not subject to amortization	2,221	—	95,242
Total property acquisition costs	2,221	210	518,075
Exploration costs(1)	125,889	23,844	59,422
Development costs	541,512	245,058	362,011
Total costs incurred	$ 669,622	$ 269,112	$ 939,508

(1) Amount includes $1.2 million, $6.6 million and $14.6 million of exploration costs related to the Company's operations in offshore Mexico for the years ended December 31, 2022, 2021 and 2020, respectively.

Estimated Quantities of Proved Oil, Natural Gas and NGL Reserves

The Company employs full-time experienced reserve engineers and geologists who are responsible for determining proved reserves in compliance with SEC guidelines. There are numerous uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production and timing of development expenditures. The reserve data in the following tables only represent estimates and should not be construed as being exact. Engineering reserve estimates were prepared based upon interpretation of production performance data and subsurface information obtained from the drilling of existing wells. The Company's Director of Reserves, internal reservoir engineers and geologists analyzed and prepared reserve estimates on all oil and natural gas fields. All of the Company's proved oil, natural gas and NGL reserves are located in the U.S. Gulf of Mexico.

At, December 31, 2022, 2021 and 2020, 100% of proved oil, natural gas and NGL reserves attributable to all of the Company's oil and natural gas properties were estimated and compiled for reporting purposes by the Company's reservoir engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), independent petroleum engineers and geologists.

The following table presents the Company's estimated proved reserves at its net ownership interest:

	Oil (MBbls)	Gas (MMcf)	NGL (MBbls)	Oil Equivalent (MBoe)
Total proved reserves at December 31, 2019	106,754	155,998	8,981	141,735
Revision of previous estimates	(14,633)	(56,358)	(168)	(24,195)
Production[1]	(13,665)	(28,652)	(1,559)	(19,999)
Purchases of reserves	26,903	181,872	3,528	60,743
Extensions and discoveries	3,948	4,348	76	4,749
Total proved reserves at December 31, 2020	109,307	257,208	10,858	163,033
Revision of previous estimates	13,619	8,979	5,137	20,252
Production	(16,159)	(32,795)	(1,875)	(23,500)
Extensions and discoveries	997	2,961	315	1,806
Total proved reserves at December 31, 2021	107,764	236,353	14,435	161,591
Revision of previous estimates	(5,625)	(8,302)	(2,002)	(9,010)
Production	(14,561)	(32,215)	(1,793)	(21,723)
Sales of reserves	(158)	(7,625)	—	(1,429)
Extensions and discoveries	3,639	31,340	2,288	11,150
Total proved reserves at December 31, 2022	91,059	219,551	12,928	140,579
Total proved developed reserves as of:				
December 31, 2020	85,007	204,054	8,104	127,120
December 31, 2021	93,420	186,442	11,792	136,286
December 31, 2022	80,285	161,727	9,315	116,555
Total proved undeveloped reserves as of:				
December 31, 2020	24,300	53,154	2,754	35,913
December 31, 2021	14,344	49,911	2,643	25,305
December 31, 2022	10,774	57,824	3,613	24,024

(1) Excludes approximately 3.0 MBoe of Mexico well test production.

During 2022, proved reserves decreased by 21.0 MMBoe primarily due to a decrease of 21.7 MMBoe of production. Additionally, there was a decrease of 9.0 MMBoe primarily due to timing of development of certain PUD locations to move beyond five years at the Phoenix Field in the Green Canyon core area and sales of reserves of 1.4 MMBoe primarily related to the Brushy Creek Field in the Shelf and Gulf Coast core area. The decrease was partially offset by 11.2 MMBoe of estimated proved reserves from extensions and discoveries primarily from evaluations of the Pompano Field and the Ram Powell Field located in the Mississippi Canyon core area.

During 2021, proved reserves decreased by 1.4 MMBoe primarily due to a decrease of 23.5 MMBoe of production. The decrease was partially offset by revision to previous estimates of 20.3 MMBoe due to increase in commodity prices as well as 1.8 MMBoe of estimated proved reserves from extensions and discoveries primarily from an evaluation of Crown and Anchor Field located in the Mississippi Canyon core area.

During 2020, proved reserves decreased by 21.3 MMBoe primarily due to a decrease of 20.0 MMBoe of production and revision to previous estimates of 24.2 MMBoe due to decrease in commodity prices. The decrease was partially offset by the addition of 60.7 MMBoe added through purchases from the ILX and Castex Acquisition, Castex Energy 2005 Acquisition and LLOG Acquisition as well as 4.7 MMBoe of estimated proved reserves from extensions and discoveries primarily from an evaluation of Green Canyon 18 and Claiborne Fields.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil, Natural Gas and NGL Reserves

The following table reflects the standardized measure of discounted future net cash flows relating to the Company's interest in proved oil, natural gas and NGL reserves (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Future cash inflows	$ 10,674,896	$ 8,496,005	$ 4,927,497
Future costs:			
Production	(1,906,752)	(1,868,818)	(1,105,211)
Development and abandonment	(1,873,453)	(1,422,507)	(1,236,874)
Future net cash flows before income taxes	6,894,691	5,204,680	2,585,412
Future income tax expense	(1,114,409)	(676,778)	(141,515)
Future net cash flows after income taxes	5,780,282	4,527,902	2,443,897
Discount at 10% annual rate	(1,411,834)	(1,087,291)	(538,963)
Standardized measure of discounted future net cash flows	$ 4,368,448	$ 3,440,611	$ 1,904,934

Future cash inflows are computed by applying SEC Pricing to year-end quantities of proved reserves. The discounted future cash flow estimates do not include the effects of derivative instruments. See the following table for SEC Pricing used in determining the standardized measure:

	Year Ended December 31,		
	2022	2021	2020
Oil price per Bbl	$ 96.03	$ 67.14	$ 39.47
Natural gas price per Mcf	$ 6.80	$ 3.71	$ 1.97
NGL price per Bbl	$ 33.89	$ 26.62	$ 9.89

Future net cash flows are discounted at the prescribed rate of 10%. Actual future net cash flows may vary considerably from these estimates. Although the Company's estimates of total proved reserves, development and abandonment costs and production rates were based on the best information available, the development and production of oil and gas reserves may not occur in the periods assumed. All estimated costs to settle asset retirement obligations associated with our proved reserves have been included in our calculation of development and abandonment of the standardized measure of discounted future net cash flows for each period presented. Actual prices realized, costs incurred and production quantities may vary significantly from those used. Therefore, such estimated future net cash flow computations should not be considered to represent the Company's estimate of the expected revenues or the current value of existing proved reserves.

Changes in Standardized Measure of Discounted Future Net Cash Flows

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved oil, natural gas and NGL reserves are as follows (in thousands):

	Year Ended December 31,		
	2022	2021	2020
Standardized measure, beginning of year	$ 3,440,611	$ 1,904,934	$ 2,537,595
Sales and transfers of oil, net gas and NGLs produced during the period	(1,340,400)	(957,576)	(339,557)
Net change in prices and production costs	2,388,442	2,049,980	(1,468,304)
Changes in estimated future development and abandonment costs	(84,391)	(57,876)	32,589
Previously estimated development and abandonment costs incurred	20,107	69,125	46,143
Accretion of discount	392,600	199,849	299,302
Net change in income taxes	(327,265)	(391,834)	361,875
Purchases of reserves	—	—	730,611
Sales of reserves	(5,218)	—	—
Extensions and discoveries	202,239	45,485	71,589
Net change due to revision in quantity estimates	(255,743)	426,357	(309,338)
Changes in production rates (timing) and other	(62,534)	152,167	(57,571)
Standardized measure, end of year	$ 4,368,448	$ 3,440,611	$ 1,904,934

Note 15 — Subsequent Events

EnVen Acquisition

For additional information, see the following:

- Note 3 — *Acquisitions*
- Note 7 — *Debt*
- Note 11 — *Related Party Transactions*

Schedule I. Condensed Financial Information of Registrant

TALOS ENERGY INC. (PARENT ONLY)
BALANCE SHEETS
(In thousands, except share amounts)

	Year Ended December 31,	
	2022	2021
ASSETS		
Current assets:		
Accounts receivable:		
Other, net	$ —	$ 523
Prepaid assets	169	141
Other current assets	36	—
Total current assets	205	664
Other long-term assets:		
Investments in subsidiaries	1,168,053	761,739
Total assets	$ 1,168,258	$ 762,403
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 249	$ 178
Accrued liabilities	728	497
Other current liabilities	62	—
Total current liabilities	1,039	675
Long-term liabilities:		
Other long-term liabilities	1,643	1,075
Total liabilities	2,682	1,750
Stockholders' equity:		
Preferred stock, $0.01 par value; 30,000,000 shares authorized and no shares issued or outstanding as of December 31, 2022 and 2021	—	—
Common stock $0.01 par value; 270,000,000 shares authorized; 82,570,328 and 81,881,477 shares issued and outstanding as of December 31, 2022 and 2021, respectively	826	819
Additional paid-in capital	1,699,799	1,676,798
Accumulated deficit	(535,049)	(916,964)
Total stockholders' equity	1,165,576	760,653
Total liabilities and stockholders' equity	$ 1,168,258	$ 762,403

See accompanying notes.

TALOS ENERGY INC. (PARENT ONLY)
STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31,		
	2022	2021	2020
Operating expenses:			
General and administrative expense	$ 2,145	$ 1,322	$ 1,404
Total operating expenses	2,145	1,322	1,404
Operating expense	(2,145)	(1,322)	(1,404)
Interest income (expense)	—	(5)	7
Other expense	(1)	(2)	(2)
Equity earnings (loss) from subsidiaries	385,968	(180,548)	(431,446)
Net income (loss) before income taxes	383,822	(181,877)	(432,845)
Income tax expense	(1,907)	(1,075)	(32,760)
Net income (loss)	$ 381,915	$ (182,952)	$ (465,605)

See accompanying notes.

TALOS ENERGY INC. (PARENT ONLY)
STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2022	**2021**	**2020**
Cash flows from operating activities:			
Net cash provided used in operating activities	$ (809)	$ (876)	$ (936)
Cash flows from investing activities:			
Distributions from subsidiaries	809	879	943
Contributions to subsidiaries	—	(3)	(71,107)
Net cash provided by (used in) investing activities	809	876	(70,164)
Cash flows from financing activities:			
Proceeds from issuance of common stock	—	—	71,100
Net cash provided by financing activities	—	—	71,100
Net increase (decrease) in cash and cash equivalents	—	—	—
Cash and cash equivalents:			
Balance, beginning of period	—	—	—
Balance, end of period	$ —	$ —	$ —

See accompanying notes.

TALOS ENERGY INC. (PARENT ONLY)
NOTES TO CONDENSED FINANCIAL STATEMENTS
December 31, 2022

Note 1 — Basis of Presentation

Pursuant to the rules and regulations of the SEC, the parent only condensed financial information of Talos Energy, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with GAAP. Therefore, these condensed financial statements should be read in conjunction with the consolidated financial statements and related notes included under Part IV, Item 15. Exhibits and Financial Statement Schedules in this Annual Report.

MANAGEMENT TEAM

TIMOTHY S. DUNCAN
President and Chief Executive Officer

JOHN A. PARKER
Executive Vice President – New Ventures

ROBERT D. ABENDSCHEIN
Executive Vice President
and Chief Operating Officer

SHANNON E. YOUNG, III
Executive Vice President
and Chief Financial Officer

WILLIAM S. MOSS III
Executive Vice President,
General Counsel and Secretary

ROBIN FIELDER
Executive Vice President – Low Carbon
Strategy and Chief Sustainability Officer

JOHN B. SPATH
Senior Vice President – Drilling
and Production Operations

GREG BABCOCK
Vice President and Chief
Accounting Officer

MEGAN DICK
Vice President - Human Resources

SERGIO L. MAIWORM JR.
Vice President – Finance,
Investor Relations and Treasurer

DEBORAH HUSTON
Vice President and Deputy
General Counsel

C. GORDON LINDSEY
Vice President - Corporate Development

BOARD OF DIRECTORS

NEAL P. GOLDMAN[1]
Managing Member, SAGE Capital
Investments, LLC

TIMOTHY S. DUNCAN
President and Chief Executive Officer,
Talos Energy Inc.

JOHN BRAD JUNEAU
Sole Manager and General Partner,
Juneau Exploration, L.P.

DONALD R. KENDALL, JR
Director and Chief Executive Officer,
Kenmont Capital Partners

RICHARD SHERRILL
President, Clean Aire Partners

CHARLES M. SLEDGE
Retired Chief Financial Officer,
Cameron International

SHANDELL SZABO
Retired Vice President of U.S.
Exploration, Anadarko Petroleum
Corporation

PAULA R. GLOVER
President, Alliance to Save Energy

(1) Chairman of the Board

CORPORATE OFFICE
333 Clay St., Suite 3300
Houston, TX 77002
Phone: 713-328-3000

WEBSITE
www.talosenergy.com

STOCK EXCHANGE LISTING
New York Stock Exchange
Symbol: TALO

ANNUAL MEETING
May 9, 2023
10:00 a.m. CT
Three Allen Center
333 Clay St., Suite 3300
Houston, TX 77002

FORM 10-K
Copies of the corporation's 10-K
are available on our website at
www.talosenergy.com

AUDITORS
Ernst & Young
Houston, TX

SHAREHOLDER SERVICES
Computershare
Mailing: P.O. Box 505000
Louisville, KY 40233
1-800-962-4284 (Toll-Free)
1-781-575-3120 (International)

OVERNIGHT MAIL
462 South 4th Street
Suite 1600
Louisville, KY 40202

INVESTOR RELATIONS
Additional corporate information
is available on our website at
www.talosenergy.com

CORPORATE OFFICE
333 Clay St., Suite 3300
Houston, TX 77002
Phone: 713-328-3000
www.talosenergy.com

TALOS ENERGY