TALOS ENERGY

2021

TALOS ENERGY
ANNUAL REPORT

Innovation & Leadership

Talos Energy
AT A GLANCE

Talos Energy is leveraging its unique capabilities and rich heritage to position itself as a leading energy business of tomorrow.

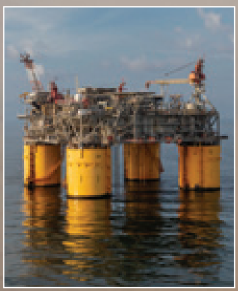
As one of the largest independent energy companies in the U.S. Gulf of Mexico, Talos maintains a strong technical skill set focused on conventional geology, geophysics and reservoir engineering as well as decades of operational experience spanning from the U.S. Gulf Coast to ultra-deepwater in the Gulf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

Talos is also applying its core skill sets to develop numerous major carbon capture and sequestration projects along the U.S. 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 of the future.

NYSE: TALO

Asset Overview

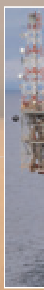
Key Talos Facilities


RAM POWELL

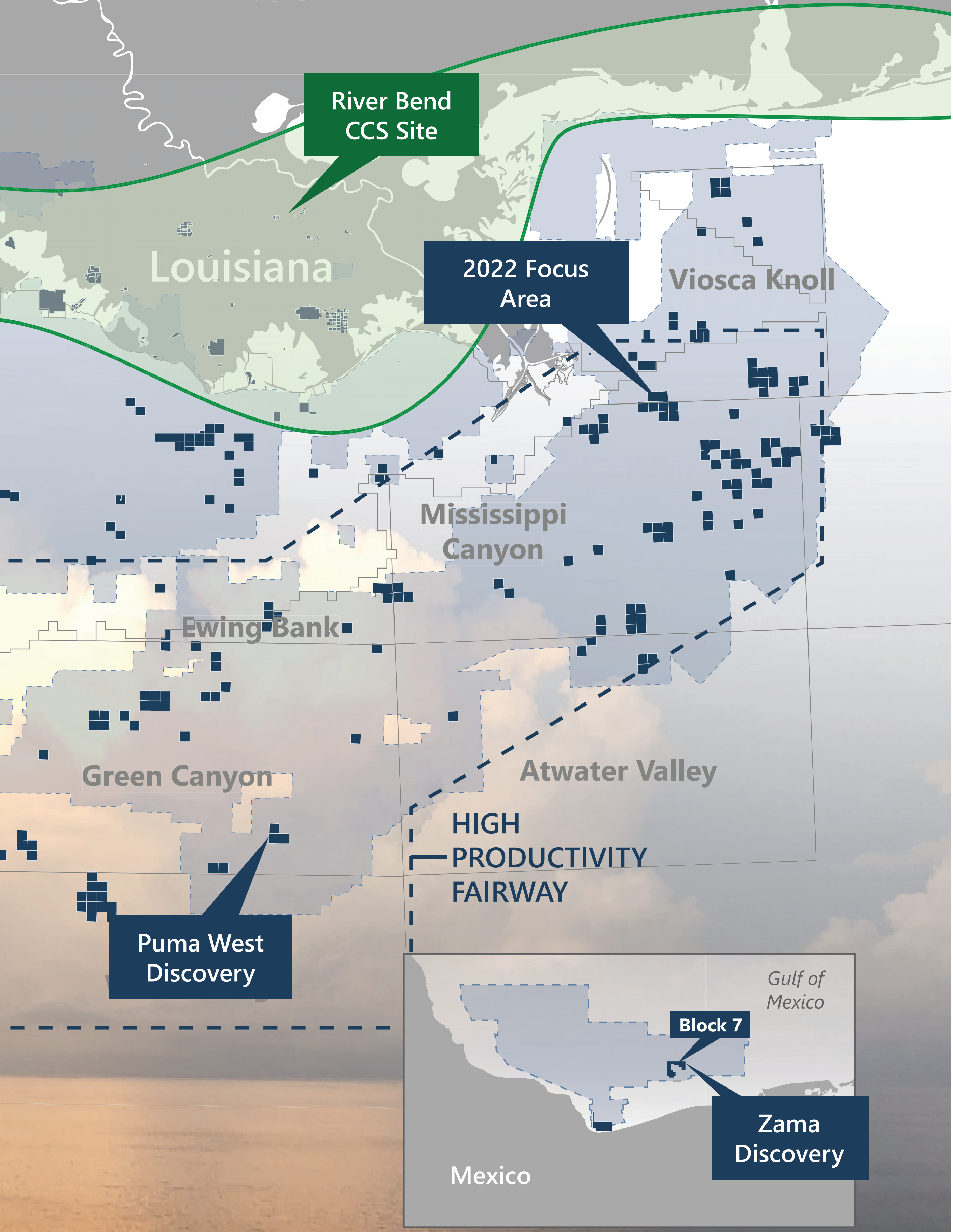

HP-1


AMBERJACK


POMPANO



TALOS ENERGY


River Bend
CCS Site
Louisiana
2022 Focus
Area
Viosca Knoll
Mississippi
Canyon
Ewing Bank
Green Canyon
Atwater Valley
HIGH
PRODUCTIVITY
FAIRWAY
Puma West
Discovery
Gulf of
Mexico
Block 7
Zama
Discovery
Mexico

GC-18

Letter to Shareholders

APRIL 2022

2021 was a historic year for Talos Energy. Not only did our company manage through the unprecedented challenge created by the COVID-19 pandemic, but in 2021 we rebounded with record breaking production, our best year of safety and environmental performance and rapid progress on our emissions reduction targets.

Despite these achievements, We are continuing to reflect on what our mission is – how do we balance building a responsible oil and gas company, delivering the energy that society needs today, while also leading the energy transition by helping to reduce industrial emissions and improve the climate in the future. We think we can and have shifted from solely an oil and gas company to a total energy solutions company to deliver on that ambition. In 2021, we made significant progress on this journey with the launch of our Carbon Capture and Sequestration ("CCS") business to complement our growing Upstream oil and gas business.

In our Upstream business, Talos achieved record production in three separate quarters, optimizing our asset base while bringing online key projects throughout the year. Utilizing our largely Talos-owned infrastructure footprint, this incremental growth contributed to strong margins for the year and, with a moderate capital budget, allowed for strong free cash flow generation. Throughout the year we continued to strengthen our balance sheet by improving leverage metrics and increasing liquidity. Ultimately, we closed the year as the largest, strongest and best-positioned organization we've ever been since our founding a decade ago.

The success of our past year is a reflection of our resilient asset base and our strategy that allows for flexibility, balance and growth. For example, the platform rig program at our Green Canyon 18 facility provided low-risk, quick cycle time opportunities that contributed to strong cash flow within the year.

In contrast, we also achieved a major discovery with our Puma West exploration prospect, a testament to the high-impact, organic opportunities available within our portfolio. In 2022, we aim to continue this trend, moving the platform rig program to our Pompano facility for a series of development and exploitation projects while also separately targeting multiple higher impact sub-sea drilling activities in proximity to our operated facilities in the Mississippi Canyon area that could be meaningful contributors to production and cash flow in the future. We also look forward to appraising the 2021 Puma West discovery later this year.

Talos has continued to be a leader in the categories of safety and environmental responsibility. 2021 was our best year ever with respect to reducing our lost time incident rates and greenhouse gas ("GHG") emissions intensity. We continue to strive for improvements in safety and environmental stewardship and have established long-term GHG emissions intensity targets, setting our course for continued reductions through 2025. In addition, we continued our active community support efforts and charitable contributions, and I'm proud to report that we've yet again been named a Top Workplace by the Houston Chronicle for the ninth straight year.

The first step of our evolution into being a more dynamic energy solutions company was to build an employee-led working team to explore ways to best leverage our conventional expertise and operational experience to become a meaningful contributor in a decarbonizing economy.

(Continued on Page 3)

"We have evolved from one of the top independent energy producers in the Gulf of Mexico to a total energy solutions company focused on both energy production and industrial carbon capture and sequestration and we are excited about the role we will play going forward in the future of our industry."

Timothy Duncan, President and Chief Executive Officer

Our team advanced CCS as a natural fit for Talos because it requires a deep understanding of how to handle, transport and inject CO_2, a hydrocarbon by-product, in saline-based conventional reservoirs deep below the earth's surface. These reservoirs are abundant along the U.S. Gulf Coast. We rapidly moved to establish ourselves in that evolving marketplace. With early success at the Texas General Land Office ("GLO") process in August, we established the first offshore dedicated CO_2 sequestration site in U.S. history which will service industrial emissions in the Beaumont and Port Arthur areas. From there we accelerated our efforts and expanded our focus across the Gulf Coast. I'm proud to say that in a matter of months our team matured an emerging concept into an industry-leading portfolio of CCS opportunities along the Gulf Coast, with four projects at the time of this letter, including the Texas GLO, industrial areas along the Mississippi River, Corpus Christi and a partnership with Freeport LNG to help decarbonize their LNG products. We are excited about our new low-carbon business and look forward to continuing our progress in 2022 and beyond.

We have also seen first-hand the importance of sound energy policy that supports access to secure, affordable energy supply for every individual on the planet. After all, lower energy prices enable commuters to drive that extra mile for a new job, or to save a little extra each month for college. Affordable energy enables small businesses to produce goods and provide services at a lower cost and enables residents to heat and cool their homes with less impact on the family budget. It is clear that oil and gas must and will remain significant contributors to the supply of energy to meet global energy demand and to help everyone reach their full potential.

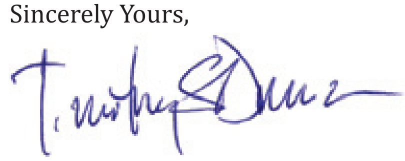
Can an energy company grow its oil and gas business to meet the energy demands of today while also being a leader in environmental stewardship and reducing its GHG intensity? And can an energy company use its skill sets and people to directly reduce industrial emissions in local communities? We believe that Talos is such an energy company.

TIMOTHY DUNCAN
TALOS ENERGY CEO

We're proud of the critical role we play in providing affordable, secure, reliable energy that improves lives, and we look forward to playing an important role in decarbonization through CCS at the same time. As a society, we need the products and services that are made possible by oil and gas – they are critical to our way of life. However, we should strive to produce those products and services as responsibly as possible. Talos has a role to play in providing the solution.

In closing, Talos possesses both a skill set and an opportunity set that is unique among U.S. energy companies today. Though we share certain similarities across many peer groups, none offer the differentiated set of catalysts that Talos possesses, including conventional offshore exploration expertise, leadership in the rapidly emerging CCS industry and a well-earned position as a logsical consolidator in the Gulf of Mexico and beyond. Focusing on our strengths and our core skills has allowed Talos to emerge from a small start-up to a leading offshore independent producer in just ten years, and I believe our opportunity set can accelerate our growth in the next ten years.

Sincerely Yours,



Timothy S. Duncan
President and Chief Executive Officer

"Over what has been a turbulent decade in the energy industry, Talos has steadily built a solid business focused around our differentiated skill sets, unique investment thesis and strong financial principles. We are well positioned for long-term success with this platform."

Shane Young, Executive Vice President and Chief Financial Officer

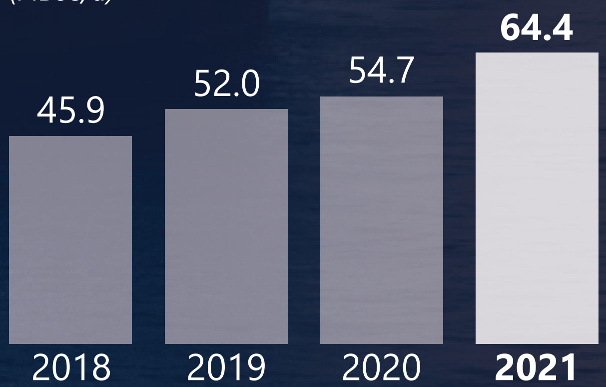
2021 Financial Highlights

2018-2021 FISCAL YEARS

Year Ended (Millions)	2021	2020	2019	2018
Revenue	$1,244.5	$575.9	$908.1	$891.3
Net Income (Loss)	($183.0)	($465.6)	$58.7	$221.5
Capital Expenditures[1]	$338.8	$405.5	$545.7	$390.6
Total Long-term Debt[2]	$1,071.3	$1,055.3	$826.5	$766.2
Reserves[3] (MMBoe)				
Proved Developed Producing (PDP)	95.6	89.7	68.3	78.1
Proved Developed Non-Producing (PDNP)	40.6	37.4	29.6	37.5
Proved Developed	136.3	127.1	97.9	115.5
Proved Undeveloped (PUD)	25.3	35.9	43.8	36.2
Total Proved	**161.6**	**163.0**	**141.7**	**151.7**
Production				
Sales Volume (MMBoe)	23.5	20.0	19.0	16.7
Average Daily Production (MBoe/d)	64.4	54.7	52.0	45.9

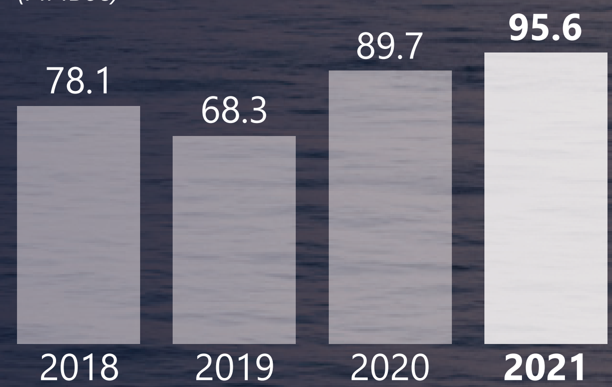
AVERAGE DAILY PRODUCTION

(MBoe/d)



PDP RESERVES

(MMBoe)



(1) Includes plugging and abandonment.
(2) Includes finance lease and excludes original issue discounts and deferred financing costs.
(3) All reserves figures at year-end SEC prices of $67.14/bbl WTI and $3.71/mcf HH, $39.47/$1.97, $61.01/$2.59, $69.42/$3.08, for 2021, 2020, 2019, and 2018, respectively.

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 refer to this business combination as the "Stone Combination," and its date of consummation, May 10, 2018, as the "Stone Closing Date."

We are 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.") Gulf of Mexico and offshore Mexico both upstream through oil and gas exploration and production and downstream through the development of future carbon capture and storage 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 carbon capture and storage collaborative arrangements along the coast of the U.S. Gulf of Mexico.

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 safely and responsibly optimize production and recovery from our assets. 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 hydrocarbon reserves, production, cash flow and future growth opportunities in a capital efficient manner, while exploring potential carbon capture and sequestration ("CCS") opportunities with aspirations to become a contributor to U.S. emissions reduction goals. Our deep technical expertise and extensive physical operating experience allow us to successfully manage our hydrocarbon business asset base and consistently make attractive acquisitions, thereby increasing stockholder value over time. Additionally, we believe these same core competencies can be utilized to develop and commercialize future CCS opportunities.

Hydrocarbon 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.

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.

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.

  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.

- ***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. Consolidation 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, Environmental Responsibility and Sustainability 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 2021, 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 second 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 intends to leverage our experience and technical expertise in the U.S. Gulf of Mexico, including sub-surface engineering expertise, seismic data sets and interpretation capabilities, operational experience offshore and along the coast and a solid track record of safety and environmentally responsible operations. The U.S. Gulf of Mexico coast ("Gulf Coast") is a critical industrial region with a large emissions footprint, while the underlying conventional geology in the area is believed by us to be ideal for carbon sequestration. We intend to provide carbon dioxide removal solutions to assist industrial partners with carbon emissions capture, transportation and injection into sequestration sites that we intend to operate in the region.

Future CCS project opportunities and the associated sequestration sites can generally be categorized into two project classifications where we intend to identify, lease and operate in order to increase stockholder value:

- ***Regional Hub Projects*** **—** These will be large, contiguous sequestration sites located nearby large industrial emissions centers in which we could consolidate carbon emissions from multiple contributing sources and develop large-scale CCS projects. Hub projects can be characterized by their large size, population of diverse contributing emitters and central proximity to major emitting regions.

- ***Point Source Projects*** **—** These will be 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 can be characterized by their smaller scale, individual emissions source (i.e. one plant) and location nearby or on-site to that emissions source. Point source projects may carry a wider range of commercial structures than hub projects due to their customized and directly negotiated nature, and we believe the total number of point source opportunities along the U.S. Gulf Coast to be significant.

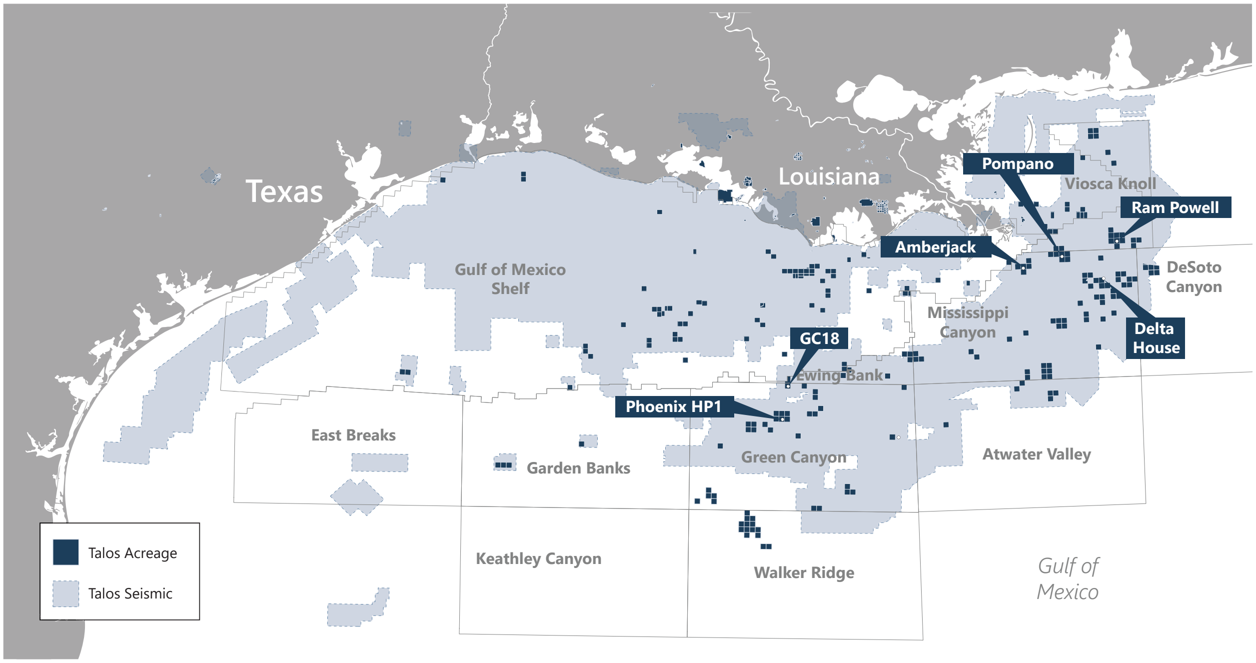
Hydrocarbon Properties

United States Gulf of Mexico

Our area of focus in the United States is the Gulf of Mexico Deepwater. Our strategy is focused 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 believe our Deepwater operations in the U.S. Gulf of Mexico provide significant potential growth opportunities through our planned 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 of December 31, 2021, our core areas in the United States are illustrated below:



The following table sets forth a summary of certain key 2021 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	52,777	79%	14%	7%	81%	7,765	98%
Mississippi Canyon	67,349	75%	16%	9%	90%	9,643	52%
Shelf & Gulf Coast	41,465	38%	51%	11%	79%	6,092	53%
Total United States	161,591	67%	24%	9%	84%	23,500	68%

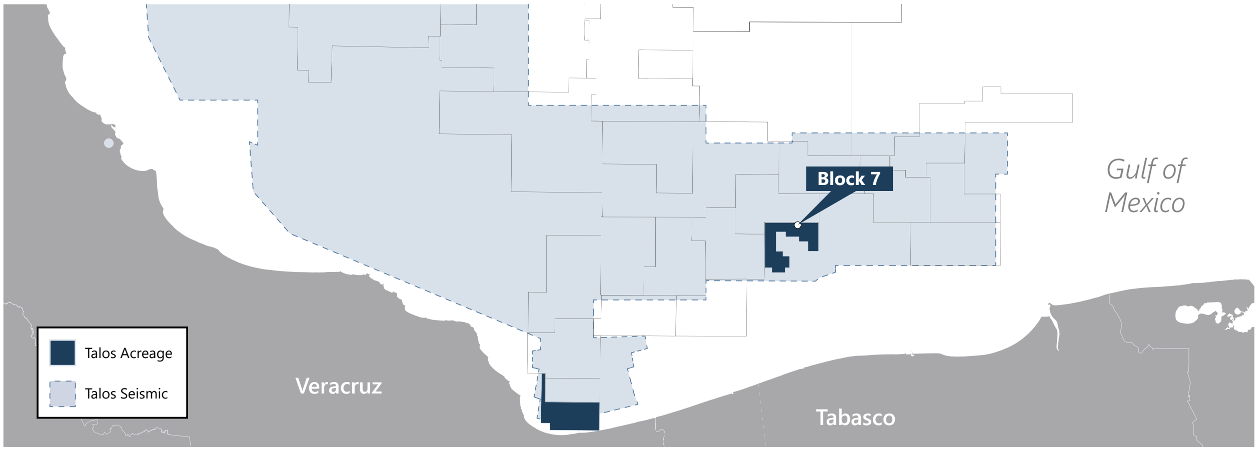
Green Canyon — Green Canyon is a Deepwater region in the Central U.S. Gulf of Mexico and is a key focus area both industry-wide and for our exploration activities. We operate two production facilities in the region, including a floating production unit, the Helix Producer I ("HP-I"), that is leased from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

Our area of focus in Mexico is Block 7 located within the Sureste Basin, a prolific proven hydrocarbon province, in the shallow waters off the coast of Mexico's Tabasco state. As of December 31, 2021, our core area in Mexico 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 ("PI") 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.

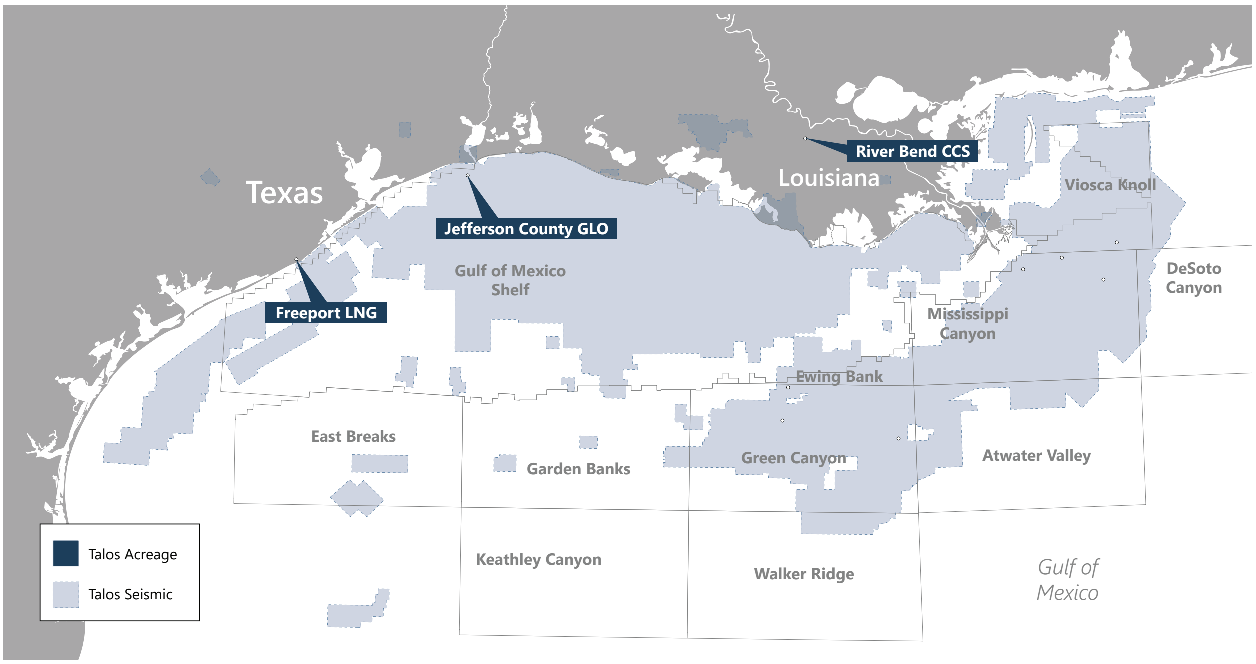
Upon conclusion of the three well appraisal program, we determined that the Zama Field likely extended into a nearby offshore block owned by Petróleos Mexicanos ("PEMEX"). On July 7, 2020, we received a notice from Mexico's Secretaría de Energía ("Ministry of Energy" or "SENER") instructing the Block 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.

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%.

***Block 31* —** We own a 25% PI in Block 31, which is operated by Hokchi Energy, S.A. de C.V. ("Hokchi"), a subsidiary of Pan American Energy LLC. To date, we have participated in a two-well drilling campaign that was conducted during 2019. In considering the appraisal program proposed by Hokchi for Block 31, we made an election to non-consent the program in order to allow us to allocate capital to other projects. 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. This non-cash impairment is presented in "Write-down of oil and natural gas properties" on our Consolidated Statements of Operations in Part IV, Item 15. Exhibits and Financial Statement Schedules.

Carbon Capture & Sequestration

We are leveraging decades of experience with conventional geology and offshore energy operations to pursue our goal of developing future carbon capture and storage opportunities. We are actively evaluating potential project opportunities through our collaborative arrangements along the U.S. Gulf Coast. Our areas of development are illustrated below:



***Jefferson County GLO Hub Project* —** In August 2021, we, along with partner Carbonvert, Inc., were selected as the winning bidder for the Texas General Land Office's ("GLO") Jefferson County carbon storage site. The successful bid makes us the operator of what we expect to be the first large-scale offshore carbon storage location in the United States near the Beaumont and Port Arthur, Texas industrial corridor. As of December 31, 2021, the lease with the Texas GLO remained subject to negotiation of final terms, which we expect to conclude and finalize in mid-2022.

***Freeport LNG Point Source Project* —** In November 2021, we announced that, along with partner Storegga Geotechnologies Limited ("Storegga"), we had executed a letter of intent with an affiliate of Freeport LNG Development, L.P. ("Freeport LNG") to develop a CCS 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 with up to a 30-year injection term, and thus the project benefits from a dedicated source of carbon dioxide ("CO_2") and a secured injection site in close physical proximity. The companies anticipate first injection could occur by the end of 2024. As of December 31, 2021, definitive documentation with Freeport LNG remained subject to negotiation of final terms, which we expect to conclude and finalize in early 2022.

River Bend Hub Project — In February 2022, we announced our entry into (i) a lease agreement for a major carbon capture and sequestration project along the Mississippi River industrial corridor and (ii) a memorandum of understanding with EnLink Midstream, LLC ("EnLink") to jointly develop a carbon capture, transportation and sequestration joint service offering focused on the Mississippi River industrial corridor. The joint service offering is being marketed to potential customers by both us and EnLink. The lease agreement will allow for three sequestration sites near EnLink's existing pipelines. We will be the project manager and operator of the injection, storage, and monitoring and will be joined by our partner, Storegga.

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, 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	25,305		253,819
Total proved	107,764	236,353	14,435	161,591	$ 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
December 31, 2019						
Proved developed producing	53,777	64,192	3,855	68,331		$ 1,837,964
Proved developed non-producing	18,239	51,189	2,878	29,648		378,244
Total proved developed	72,016	115,381	6,733	97,979		2,216,208
Proved undeveloped	34,738	40,617	2,248	43,756		776,814
Total proved	106,754	155,998	8,981	141,735	$ 2,537,595	$ 2,993,022

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,		
	2021	2020	2019
Standardized measure	$ 3,440,611	$ 1,904,934	$ 2,537,595
Present value of future income taxes discounted at 10%	485,386	93,551	455,427
PV-10 (Non-GAAP)	$ 3,925,997	$ 1,998,485	$ 2,993,022

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, 2020	127,120
Changes during the year:	
Production	(23,500)
Revisions of previous estimates	15,076
Additions	1,806
Conversion to proved developed producing reserves	15,784
Total proved developed reserves changes	9,166
Proved developed reserves at December 31, 2021	136,286

Our proved developed reserves at December 31, 2021 increased by 9.2 MMBoe, or 7% primarily due to:

Revisions of Previous Estimates — Upward revisions of 15.1 MMBoe are primarily attributable to a 13.2 MMBoe increase in commodity prices as well as net increase of 1.9 MMBoe in performance revisions across our core areas.

Additions — Additions of 1.8 MMBoe are primarily attributable to the successful drilling in the Crown and Anchor Field located in the Mississippi Canyon 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, 2020	35,913	$ 315,453
Changes during the year:		
Revisions of previous estimates	5,176	64,423
Conversion to proved developed producing reserves	(15,784)	(71,844)
Total proved undeveloped reserves changes	(10,608)	(7,421)
Proved undeveloped reserves at December 31, 2021	25,305	$ 308,032

Our PUD reserves at December 31, 2021 decreased by 10.6 MMBoe, or 30% primarily due to:

Revisions of Previous Estimates — Upward revisions of 5.2 MMBoe are primarily attributable to an increase in commodity prices across our core areas.

Conversion to Proved Developed Producing — Conversions of 15.8 MMBoe are primarily attributable to our Deepwater drilling campaign which included successful development wells in our Phoenix Field and Grand Canyon 18 Field located in the Green Canyon 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, 2021 totaled approximately $308.0 million, of which $123.0 million, $93.7 million and $91.3 million is attributable to our Green Canyon, Shelf and Gulf Coast and Mississippi Canyon 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 2022 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, 2021, 2020 and 2019, 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, 2021, 2020 and 2019 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 2021 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 47 years of industry experience with positions of increasing responsibility, including 39 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 47 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, 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
December 31, 2019														
United States	3.0	2.3	1.0	0.8	4.0	3.1	3.0	2.7	—	—	3.0	2.7	7.0	5.8
Mexico	—	—	2.0	0.5	2.0	0.5	—	—	—	—	—	—	2.0	0.5
Total	3.0	2.3	3.0	1.3	6.0	3.6	3.0	2.7	—	—	3.0	2.7	9.0	6.3

(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, 2021, 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	—	—	1.0	1.0	1.0	0.3	—	—
Mexico[(1)]	—	—	—	—	4.0	1.5	—	—
Total	—	—	1.0	1.0	5.0	1.8	—	—

(1) Excludes 2.0 gross and 0.5 net exploratory wells suspended or waiting on completion previously disclosed related to our Mexico Block 31 lease that as of December 31, 2021 have been fully impaired due to our non-consent of the appraisal program. See Part I, Items 1 and 2. Business and Properties — Hydrocarbon Properties — *Mexico — Block 31* for additional information.

Productive Wells

The number of our productive wells is as follows for the year ended December 31, 2021:

	Gross	Net
Crude oil	198.0	148.7
Natural gas	70.0	38.8
Total[(1)]	268.0	187.5

(1) Includes 8.0 gross and 6.7 net wells with dual completions.

Acreage

Gross and net developed and undeveloped acreage is as follows for the year ended December 31, 2021:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
United States:						
Deepwater[(1)]	280,913	137,171	490,705	206,735	771,618	343,906
Shelf	287,894	176,295	127,287	99,988	415,181	276,283
Total United States	568,807	313,466	617,992	306,723	1,186,799	620,189
Mexico[(2)]	—	—	69,530	17,843	69,530	17,843
Total	568,807	313,466	687,522	324,566	1,256,329	638,032

(1) Does not include 57.6 gross and 36.7 net undeveloped acres from the November 2021 Federal Lease Sale in which we were the apparent high bidder. As of December 31, 2021, the BOEM has not awarded these leases. See Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Significant Developments — *Federal Lease Sale* for additional information.

(2) Includes 64.9 gross and 16.2 net undeveloped acres from our Mexico Block 31 lease that as of December 31, 2021 have been fully impaired due to our non-consent of the appraisal program. See Part I, Items 1 and 2. Business and Properties — Hydrocarbon Properties — *Mexico — Block 31* for additional information.

Undeveloped acreage is considered to be those 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 those 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, 2021 are scheduled to expire as shown in the table below (the terms of which may be extended by drilling and production operations):

	Gross	Net
2022	133,630	46,066
2023	174,813	120,090
2024	107,480	37,710
2025	46,166	25,778
2026	23,040	10,656
2027 and beyond	202,393	84,266
Total	687,522	324,566

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,		
	2021	2020	2019
Production Volumes:			
Crude oil (MBbls)	16,159	13,665	13,847
Natural gas (MMcf)	32,795	28,652	23,306
NGLs (MBbls)	1,875	1,559	1,228
Total (MBoe)	23,500	19,999	18,959
Percent of MBoe from crude oil	69%	68%	73%
Average Sales Price (including commodity derivatives):			
Crude oil (per Bbl)	$ 49.67	$ 47.36	$ 59.23
Natural gas (per Mcf)	$ 3.11	$ 2.00	$ 2.55
NGLs (per Bbl)	$ 26.54	$ 9.90	$ 16.02
Average (per Boe)	$ 40.61	$ 35.99	$ 47.43
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 65.86	$ 37.09	$ 60.17
Natural gas (per Mcf)	$ 3.98	$ 1.87	$ 2.37
NGLs (per Bbl)	$ 26.54	$ 9.90	$ 16.02
Average (per Boe)	$ 52.96	$ 28.80	$ 47.90
Average Lease Operating Expense (per Boe)	$ 12.07	$ 12.33	$ 12.84

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

Green Canyon Core Area — Phoenix Field

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

	Year Ended December 31,		
	2021	2020	2019
Production Volumes:			
Crude oil (MBbls)	4,201	4,000	4,812
Natural gas (MMcf)	3,871	3,552	4,803
NGLs (MBbls)	411	345	368
Total (MBoe)	5,257	4,937	5,980
Percent of MBoe from crude oil	80%	81%	80%
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 66.27	$ 37.53	$ 59.72
Natural gas (per Mcf)	$ 4.55	$ 2.22	$ 2.74
NGLs (per Bbl)	$ 30.05	$ 12.70	$ 15.68
Average (per Boe)	$ 58.66	$ 32.89	$ 51.23
Average Lease Operating Expense (per Boe)	$ 4.86	$ 6.12	$ 5.90

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 total estimated proved reserves:

	Year Ended December 31,		
	2021	2020	2019
Production Volumes:			
Crude oil (MBbls)	2,716	2,852	3,324
Natural gas (MMcf)	2,626	2,179	2,320
NGLs (MBbls)	254	216	236
Total (MBoe)	3,408	3,431	3,947
Percent of MBoe from crude oil	80%	83%	84%
Average Sales Price (excluding commodity derivatives):			
Crude oil (per Bbl)	$ 67.33	$ 38.51	$ 61.83
Natural gas (per Mcf)	$ 4.68	$ 2.28	$ 2.61
NGLs (per Bbl)	$ 25.54	$ 6.51	$ 14.49
Average (per Boe)	$ 59.17	$ 33.86	$ 54.49
Average Lease Operating Expense (per Boe)	$ 3.57	$ 2.90	$ 2.17

Expenditures and Costs Incurred

For information on property development, exploration and acquisition costs, see Part IV, Item 15. Exhibits and Financial Statement Schedules — Note 13 — *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, 2021, 45% and 29% of our oil, natural gas and NGL revenues were attributable to Shell Trading (US) Company 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 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 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 $175 million per named windstorm and in the aggregate, and is also subject to a maximum of $15 million per occurrence retention dependent on location. We separately maintain an operators extra expense policy with additional coverage for an amount up to $500 million for U.S. Gulf of Mexico Deepwater drilling wells, $150 million for U.S. Gulf of Mexico Shelf drilling wells, $75 million for U.S. Gulf of Mexico producing and shut-in wells, $75 million for drilling and workover in inland waters and $25 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 million in operators extra expense coverage for operations and $500 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, effectively halting implementation of the leasing suspension. 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 and directing the DOI to consider certain climate effects of awarding the leases before deciding if DOI could proceed with a new lease sale. Pursuant to the court’s ruling, the DOI will have to conduct a new environmental analysis that takes into consideration such climate effects before holding a new lease sale. If this court ruling continues to stand, all of the winning bids identified for award pursuant to this lease sale will be invalidated, including our winning bids. 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 adjusting royalty rates to ensure that the full value of the tracts being leased are captured, 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. Several of the report recommendations require action by the Congress and cannot be implemented unilaterally by the new 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 2022, the DOI lists proposed rulemaking initiatives for which notice is anticipated to be issued in the first half of 2022 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; establishing a comprehensive program for identifying, prioritizing and managing risks associated with OCS lease and grant obligations; and 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 cancelling 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. 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. For example, in the federal government's most recent list of potential regulatory actions for 2022, the BSEE lists its plans to pursue a BSEE-only rule in early 2022 that would finalize the policies and procedures concerning compliance with OCS oil and gas decommissioning obligations pursuant to the BOEM and BSEE jointly-proposed October 2020 rulemaking issued under the Trump Administration. The BOEM will not be involved in final issuance of the October 2020 rulemaking, instead indicating under the federal government's list that it will pursue a new proposed rule in respect of financial assurance, as described earlier in this section, that is anticipated to be issued in mid-2022.

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 operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states 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 PSCs that we and our consortium partners have entered into for the development of these acreages contain 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 relevant 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 waters.

***Hydrocarbon Export Regulation in Mexico* —** Our operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states 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. While these Amparo-driven suspensions apply to the entire oil and gas sector, these suspensions remain temporary in nature while the courts determine the legal validity of the regulations and amendments, and there remains the possibility that one or more of these suspensions may lifted or otherwise revised.

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 will propose a rule making 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. 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. 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 have filed litigation over this December 2020 decision, and the Biden Administration has announced plans to reconsider the December 2020 final action in favor of a more stringent ground-level ozone NAAQS. 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. As a result, 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 plans to issue a supplemental proposal enhancing this proposed rulemaking in 2022 that will contain additional requirements not included in the November 2021 proposed rule and the agency anticipates issuing a final rule by the end of 2022.

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. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States’ commitments under the Paris Agreement, COP26, or other international conventions cannot be predicted at this time.

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. 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. More recently, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. 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 has announced in the federal government's most recent list of potential regulatory actions for 2022 that it is pursuing several proposed rulemaking initiatives for which notice is anticipated to be issued in the first half of 2022 in respect to enhanced disclosures to be made by registrants for such topics as climate change, human capital management, board members and nominees and cybersecurity. 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 an issuer's existing climate disclosures misleading or deficient.

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 operations on oil and natural gas blocks in shallow waters off the coast of Mexico's Veracruz and Tabasco states 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 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. More recently, 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 PSCs, we are jointly and severally liable for the performance of all obligations under the PSCs, 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 PSCs.

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

As of December 31, 2021, we employ approximately 443 people located primarily in Texas, Louisiana and Mexico. 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.

Our human capital measures and objectives focus on several areas, including, but not limited to human rights, diversity and inclusion measures, assuring the safety of our employees, employee recruitment and development and offering a fulsome array of employee health and welfare benefits. We consider our employees a key factor in our success and 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.

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 human rights principles include pay and benefits, freedom of association, nondiscrimination and prevention of human trafficking, forced labor and child labor. In 2021, we published our Talos Human Rights Policy to further strengthen our commitment to safeguard human rights.

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 and problem-solving and leads to better decision-making and enhanced performance. In 2021, we engaged a Diversity and Inclusion professional to partner with Human Resources and our employee diversity committee to create a diversity and inclusion strategy. 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.

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. In 2021, we reaffirmed our commitment to corporate responsibility and renamed the Board's Safety Committee the Safety, Sustainability & Corporate Responsibility ("SSCR") Committee and explicitly expanded its scope and oversight to include 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 2021 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.

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 implement 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 the use of a 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. 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 4.9% turnover rate for 2021.

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 response to the COVID–19 pandemic, we transitioned office-based employees to a work from home schedule and increased safety measures and protocols for those employees choosing to report to the office, such as mandatory temperature checks, limiting third party visitors, and encouraging the use of masks and social distancing. Beginning in June 2021, our office-based employees returned to the office and protocols are in place to limit the spread of COVID-19. For our employees offshore, we increased pre-departure screenings, which included symptom reporting questionnaires, contact tracing, temperature screenings, and in some cases, negative COVID-19 tests. For our offshore facilities, we provided N95 masks and cleaning supplies, performed daily temperature checks and increased response procedures in the event an employee displayed symptoms.

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.

MANAGEMENT TEAM

TIMOTHY S. DUNCAN
President and Chief Executive Officer

JOHN A. PARKER
Executive Vice President – Exploration

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
and General Counsel

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

CHARLES M. SLEDGE
Retired Chief Financial Officer,
Cameron International

ROBERT M. TICHIO
Partner, Riverstone Holdings LLC

PAULA R. GLOVER
President, Alliance to Save Energy

(1) Chairman of the Board

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WEBSITE
www.talosenergy.com

STOCK EXCHANGE LISTING
New York Stock Exchange
Symbol: TALO

ANNUAL MEETING
May 11, 2022
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
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Houston, TX

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Louisville, KY 40233
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1-781-575-3120 (International)

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INVESTOR RELATIONS
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