UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2025.

OR

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

Commission file number 001-38770

EPSILON ENERGY LTD.
(Exact name of registrant as specified in its charter)

Alberta, Canada	**98-1476367**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

500 Dallas Street, Suite 1250
Houston, Texas 77002
(281) 670-0002
(Address of principal executive offices including zip code and telephone number, including area code)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Shares, no par value	EPSN	NASDAQ Global Market

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

NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes x No ☐

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

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

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

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

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

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

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act).

Yes ☐ No x

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $ 133.7 million. There were 30,239,980 Common Shares (no par value) outstanding as of March 26, 2026.

PART I

FORWARD LOOKING STATEMENTS.

Certain statements contained in this report constitute forward-looking statements. The use of any of the words "anticipate," "continue," "estimate," "expect," "may," "will," "project," "should," "believe," and similar expressions and statements relating to matters that are not historical facts constitute "forward looking statements" within the meaning of applicable securities laws. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated. Such forward-looking statements are based on reasonable assumptions, but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this report should not be unduly relied upon. These statements are made only as of the date of this report. All statements that address operating performance, events or developments that we expect or anticipate will occur in the future — including statements relating to oil and natural gas production rates, commodity prices for crude oil or natural gas, supply and demand for oil and natural gas; the estimated quantity of oil and natural gas reserves, including reserve life; future development and production costs, and statements expressing general views about future operating results — are forward-looking statements. Management believes that these forward-looking statements are reasonable as and when made. However, caution should be taken not to place undue reliance on any such forward-looking statements because such statements speak only as of the date when made. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. In addition, forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from our present expectations or projections. These risks and uncertainties include, but are not limited to, those described in this Annual Report on Form 10-K, and those described from time to time in our future reports filed with the Securities and Exchange Commission.

DEFINED TERMS

We have included below the definitions for certain terms used in this document:

"3-D seismic" Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

"ABCA" Business Corporations Act (Alberta).

"Anchor shippers" Parties listed in the Anchor Shipper Gas Gathering Agreement for Northern Pennsylvania, including Epsilon Energy USA, Inc., Equinor USA Onshore Properties, Inc., and Expand Energy Corporation. for the Auburn Gas Gathering System.

"ASC" Accounting Standards Codification.

"Bbl" One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil, NGLs and other liquid hydrocarbons.

"Bcf" One billion cubic feet, used in reference to natural gas.

"Boe" One stock tank barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals six Mcf of natural gas and one Bbl of crude oil equals one Bbl of natural gas liquids.

"Completion" The process of preparing a natural gas and oil wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production.

"Delay rental" Consideration paid to the lessor by a lessee to extend the terms of an oil and natural gas lease in the absence of drilling operations and/or production that is contractually required to hold the lease. This consideration is generally required to be paid on or before the anniversary date of the natural gas and oil lease during its primary term, and typically extends the lease for an additional year.

"Development well" A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Differential" The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot price, and the wellhead price received.

"Dry hole" A well found to be incapable of producing either natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

"Exit rate" Upstream term referring to the rate of production of oil and/or gas as of a specified date.

"Exploratory well" A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

"FASB" Financial Accounting Standards Board.

"Field" An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

"Free cash flow" A measure of a company's financial performance, calculated as operating cash flow minus capital expenditures. Free cash flow represents the cash that a company is able to generate after spending the money required to maintain or expand its asset base.

"GAAP" Generally accepted accounting principles in the United States of America.

"GGS" A natural gas gathering system.

"Gross acres" or *"gross wells"* The total acres or wells, as the case may be, in which a working interest is owned.

"*Henry Hub"* A natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the NYMEX. The hub is owned by Sabine Pipe Line LLC and has access to many of the major gas markets in the United States.

"ISDA" International Swaps and Derivatives Association, Inc.

"Lease operating expense" or "LOE" The expenses of lifting oil or gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs and other expenses incidental to production, but not including lease acquisition or drilling or completion expenses.

"MBbl" One thousand barrels of oil, NGLs or other liquid hydrocarbons.

"MBbl/d" One MBbl per day.

"MBoe" One thousand BOE.

"MBoe/d" One MBOE per day.

"Mcf" One thousand cubic feet, used in reference to natural gas.

"Mcfe" One thousand cubic feet equivalent, used in reference to natural gas. One Mcf of natural gas equivalent, converting one Bbl of oil or natural gas liquids at the ratio of one Bbl of oil or natural gas liquids to 6 Mcf of natural gas.

"MMBbl" One million Bbl.

"MMBoe" One million Boe.

"MMBtu" One million British Thermal Units, used in reference to natural gas.

"MMcf" One million cubic feet, used in reference to natural gas.

"MMcf/d" One MMcf per day.

"MMcfe" One million Mcfe.

"Net acres" or *"net wells"* The sum of the fractional working interests owned in gross acres or wells, as the case may be.

"NGL" Natural gas liquid.

''NYMEX'' The New York Mercantile Exchange.

''PDP'' Proved developed producing reserves.

''Plugging and abandonment'' Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of most states legally require plugging of abandoned wells.

''Prospect'' A property on which indications of oil or gas have been identified based on available seismic and geological information.

"Proved developed reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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

The area of the reservoir considered as proved includes all of the following:

a. The area identified by drilling and limited by fluid contacts, if any, and

b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based, and

b. The project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

''Proved undeveloped reserves'' or *''PUDs"* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

''PV-10'' The present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes. Unless otherwise noted, PV-10 is calculated using the pricing scheme as required by the Securities and Exchange Commission ("SEC"). PV-10 of proved reserves is calculated the same as the standardized measure of discounted future net cash flows, except that the

standardized measure of discounted future net cash flows includes future estimated income taxes discounted at 10% per annum. See the definition of standardized measure of discounted future net cash flows.

"Reasonable certainty" If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical and geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

"Reserves" Estimated remaining quantities of natural gas and oil and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering natural gas and oil or related substances to market, and all permits and financing required to implement the project.

"Reservoir" A porous and permeable underground formation containing a natural accumulation of producible crude oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"Royalty" The amount or fee paid to the owner of mineral rights, expressed as a percentage or fraction of gross income from crude oil or natural gas produced and sold, unencumbered by expenses relating to the drilling, completing or operating of the affected well.

"Royalty interest" An interest in an oil or natural gas property entitling the owner to shares of the crude oil or natural gas production free of costs of exploration, development and production operations.

"Section" An area of one square mile of land, 640 acres, with 36 sections making up one survey township on a rectangular grid.

"SOFR" The Secured Overnight Financing Rate that is generally published by the Federal Reserve Bank of New York.

"Standardized Measure" or "SMOG" The standardized measure of discounted future net cash flows (the "Standardized Measure") is an estimate of future net cash flows associated with proved reserves, discounted at 10% per annum. Future net cash flows is calculated by reducing future net revenues by estimated future income tax expenses and discounting at 10% per annum. The Standardized Measure and the PV-10 of proved reserves is calculated in the same exact fashion, except that the Standardized Measure includes future estimated income taxes discounted at 10% per annum. The Standardized Measure is in accordance with U.S. GAAP.

"Working interest" The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and to a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

"Workover" Operations on a producing well to restore or increase production.

ITEM 1. BUSINESS.

Summary

Epsilon Energy Ltd. (the "Company" or "Epsilon" or "we") was incorporated under the laws of the Province of Alberta, Canada on March 14, 2005, pursuant to the ABCA. The Company is extra-provincially registered in Ontario pursuant to the *Business Corporations Act* (Ontario). Epsilon is a North American on-shore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves. On February 14, 2019, Epsilon's registration statement on Form 10 was declared effective by the United States Securities and Exchange Commission and on February 19, 2019, we began trading in the United States on the NASDAQ Global Market under the trading symbol "EPSN."

At December 31, 2025, Epsilon's total estimated net proved reserves were 86.4 Bcf of natural gas reserves, 9.3 MMBbls of oil reserves, and 2.4 MMBbls of NGL reserves. Epsilon holds leasehold rights to approximately 101,265 gross (54,044 net) acres. The Company has natural gas production in the Appalachian Basin Pennsylvania and oil, natural gas liquids and natural gas production in the Powder River Basin in Wyoming, the Permian Basin in Texas and New Mexico, and the Western Canadian Sedimentary Basin in Alberta, Canada.

On November 14, 2025, Epsilon acquired Peak Exploration & Production LLC and Peak BLM Lease LLC and their subsidiaries (together, "Peak") for total consideration of $88.5 million consisting of 1) issuance of 5,681,489 common shares valued at $27.6 million, 2) contingent consideration of up to 2,500,000 common shares valued at $10.6 million, and the settlement of $50.3 million of debt. The contingent consideration was settled on November 19, 2025, through the issuance of 2,234,847 common shares for $10.6 million. The acquired assets primarily include operated and non-operated production and leasehold interests in the core of the Powder River Basin in Wyoming. As part of the acquisition, the Company added 17 full-time employees from Peak.

The results of operations attributable to the Peak acquisition have been included in the Company's consolidated financial statements as of the closing date of the acquisition.

We conduct operations in the United States through our wholly owned subsidiaries Epsilon Energy USA Inc., an Ohio corporation, or Epsilon Energy USA; Epsilon Midstream, LLC, a Pennsylvania limited liability company, or Epsilon Midstream; Epsilon Operating, LLC, a Delaware limited liability company; Dewey Energy GP LLC, a Delaware limited liability company; Peak Exploration & Production LLC, a Delaware limited liability company; Peak BLM Lease LLC, a Delaware limited liability company; Peak Powder River Resources, LLC, a Wyoming limited liability company (the licensed operator in the state of Wyoming); Peak Energy Operating #2, LLC, a Colorado limited liability company; Willow Springs Development, LLC, a Colorado limited liability company; Peak Powder River Acquisition, LLC, a Delaware limited liability company; and Altolisa Holdings, LLC, a Delaware limited liability company.

Substantially all the Pennsylvania acreage (4,878 net) is dedicated to the Auburn Gas Gathering System ("Auburn GGS") located in Susquehanna County, Pennsylvania for a 10-year term expiring in 2033 under an operating agreement whereby the Auburn GGS owners charge a fixed gathering and compression rate which is adjusted annually by the CPI-U All Urban Consumer Price Index published by the US Bureau of Labor Statistics. We own a 35% interest in the Auburn GGS which is operated by a subsidiary of Williams Partners, LP. In 2025, we paid $3.5 million (after elimination) to the Auburn GGS to gather and treat our 9.4 Bcf of natural gas production in Pennsylvania ($2.4 million after elimination was paid to the Auburn GGS to gather and treat our 5.7 Bcf in 2024), including the fees paid to our subsidiary, Epsilon Midstream.

Our principal executive office is located at 500 Dallas Street, Suite 1250, Houston, Texas 77002, and our telephone number at that address is (281) 670-0002. Our registered office in Alberta, Canada is located at 14505 Bannister Road SE, Suite 300, Calgary, AB, Canada T2X 3J3.

Operational Highlights of 2025

Appalachian Basin—Pennsylvania

- During the year ended December 31, 2025, Epsilon's realized natural gas price was $2.98 per Mcf, excluding the impact of hedges, a 66% increase from $1.80 for the year ended December 31, 2024.

- Total natural gas sales for the year ended December 31, 2025 were 9.4 Bcf, a 65% increase from the 5.7 Bcf sold for the year ended December 31, 2024, driven by new wells and curtailed wells returning to production.
- Gathered and delivered 40.5 Bcf gross (14.2 Bcf net to Epsilon's interest) during the year, or 111 MMcf/d through the Auburn GGS.
- In 2025, 4 gross (0.24 net) wells were turned on line in January 2025 and 3 gross (0.04) wells were turned on line in March 2025.

Permian Basin—Texas and New Mexico

- During the year ended December 31, 2025, Epsilon's realized price for all Permian Basin production was $49.19 per Boe, excluding the impact of hedges, an 8% decrease from the $53.52 per Boe for the year ended December 31, 2024.
- Total sales for the year ended December 31, 2025, including oil, natural gas, and natural gas liquids, were 212 Mboe, an 18% decrease from the 259 MBoe sold for the year ended December 31, 2024.
- In 2025, the Company participated in the drilling and completion of 1 gross (0.25 net) wells in Texas. This well went into production in July 2025.

Anadarko Basin—Oklahoma

- During the year ended December 31, 2025, Epsilon's realized price for all Oklahoma production was $4.33 per Mcfe, excluding the impact of hedges, a 0.2% decrease from $4.34 realized for the year ended December 31, 2024.
- Total sales for the year ended December 31, 2025, including oil, natural gas, and natural gas liquids, were 0.34 Bcfe, a 17% decrease from 0.41 Bcfe sold for the year ended December 31, 2024.
- In 2025, there was no development activity in Oklahoma. The Company sold all of its assets in the Anadarko Basin in December 2025.

Powder River Basin—Wyoming

- The Powder River Basin assets were acquired on November 14, 2025.
- During the period ended December 31, 2025, Epsilon's realized price for all Wyoming production was $36.91 per Boe, excluding the impact of hedges.
- Total sales for the period ended December 31, 2025, including oil, natural gas, and natural gas liquids, were 108.5 MBoe.

Western Canadian Sedimentary Basin—Alberta, Canada

- During the year ended December 31, 2025, Epsilon's realized price for all Canada production was $36.07 per Boe, excluding the impact of hedges, a 22% decrease from the $46.07 per Boe realized for the year ended December 31, 2024.
- Total sales for the year ended December 31, 2025, including oil, natural gas, and natural gas liquids, were 27.4 MBoe, a 996% increase from 2.5 MBoe sold for the year ended December 31, 2024.
- In 2025, the Company participated in the completion of 2 gross (0.5 net) wells in Canada. The two wells turned on line in March 2025.

Properties

Wells

As of December 31, 2025, Epsilon's 101,265 gross (54,044 net) acres are located in the United States and Canada and include 540 gross (90.69 net) wells. Of these wells, 105 gross (45 net) wells are operated.

	Gross[1]	Net[2]
Producing Wells		
Gas	274	33.63
Oil	194	55.42
Total Producing Wells	468	89.05
Non-Producing Wells	72	1.64
Total Wells	540	90.69

Acreage

As of December 31, 2025, our leasehold inventory consisted of the following acreage amounts, rounded to the nearest acre:

	Gross[1]	Net[2] [3]
Developed Acres		
Pennsylvania	11,398	4,878
Wyoming	10,428	6,781
Texas	3,086	771
Canada	4,138	1,273
	29,050	13,703
Undeveloped Acres		
Pennsylvania	250	250
Wyoming	50,517	32,785
Texas	13,548	3,354
Canada	7,900	3,950
	72,215	40,339
Total Acres		
Pennsylvania	11,648	5,129
Wyoming	60,945	39,566
Texas	16,634	4,126
Canada	12,038	5,223
Total acres	101,265	54,044

(1) "Gross" means one hundred percent of the working interest ownership in each leasehold tract of land.

(2) "Net" means the Company's fractional working interest share in each leasehold tract of land on which productive wells have been drilled.

(3) "Net Undeveloped" means the Company's fractional working interest share in each leasehold tract of land where productive wells have yet to be drilled.

Business Segments

Our operations are conducted by two operating segments for which information is provided in our consolidated financial statements for the years ended December 31, 2025 and 2024.

The two segments are as follows:

Upstream: Activities include interest in the acquisition, exploration, development and production of oil and natural gas reserves.

Gathering System: Interest in a natural gas gathering system.

For information about our segment's revenues, profits and losses, total capital expenditures, and total assets, see Note 14 "Operating Segments" in the Notes to Consolidated Financial Statements.

Oil and Natural Gas Production and Revenues and Gathering System Revenues

A summary of our net oil and natural gas production, average oil and natural gas prices and related revenues and our gathering system revenues for the years ended December 31, 2025 and 2024, respectively, follows:

	Year ended December 31,	
	2025	2024
Production Volumes		
Pennsylvania		
Natural gas (MMcf)	9,402	5,699
Total (MMcfe)	**9,402**	**5,699**
Permian Basin		
Natural gas (MMcf)	161	205
Natural gas liquids (MBoe)	36	52
Oil (MBbl)	149	173
Total (MMcfe)	**1,271**	**1,554**
Oklahoma		
Natural gas (MMcf)	197	237
Natural gas liquids (MBoe)	14	17
Oil (MBbl)	9	11
Total (MMcfe)	**335**	**408**
Wyoming		
Natural gas (MMcf)	189	—
Natural gas liquids (MBoe)	27	—
Oil (MBbl)	50	—
Total (MMcfe)	**651**	—
Canada		
Natural gas (MMcf)	52	—
Natural gas liquids (MBoe)	4	—
Oil (MBbl)	15	3
Total (MMcfe)	**166**	**15**
Company Total		
Natural gas (MMcf)	10,001	6,142
Natural gas liquids (MBoe)	81	69
Oil (MBbl)	223	187
Total (MMcfe)	**11,825**	**7,676**

	Year ended December 31, 2025	2024
Revenues		
Pennsylvania		
Natural gas revenue	$ 28,012,040	$ 10,247,834
Avg. Price ($/Mcf)	$ 2.98	$ 1.80
Gathering system revenue (net of elimination)	$ 6,683,735	$ 5,524,063
Total PA Revenues	**$ 34,695,775**	**$ 15,771,897**
Permian Basin		
Natural gas revenue	$ 113,038	$ 32,930
Avg. Price ($/Mcf)	$ 0.70	$ 0.16
Natural gas liquids revenue	$ 706,010	$ 1,060,967
Avg. Price ($/Bbl)	$ 19.51	$ 20.48
Oil and condensate revenue	$ 9,614,603	$ 12,770,258
Avg. Price ($/Bbl)	$ 64.50	$ 73.81
Total Permian Basin Revenues	**$ 10,433,651**	**$ 13,864,155**
Oklahoma		
Natural gas revenue	$ 640,607	$ 505,304
Avg. Price ($/Mcf)	$ 3.25	$ 2.13
Natural gas liquids revenue	$ 318,108	$ 420,991
Avg. Price ($/Bbl)	$ 22.56	$ 24.16
Oil and condensate revenue	$ 507,406	$ 844,265
Avg. Price ($/Bbl)	$ 54.11	$ 76.75
Total OK Revenues	**$ 1,466,121**	**$ 1,770,560**
Wyoming		
Natural gas revenue	$ 291,933	$ —
Avg. Price ($/Mcf)	$ 1.54	$ —
Natural gas liquids revenue	$ 872,263	$ —
Avg. Price ($/Bbl)	$ 32.48	$ —
Oil and condensate revenue	$ 2,840,537	$ —
Avg. Price ($/Bbl)	$ 56.66	$ —
Total WY Revenues	**$ 4,004,733**	**$ —**
Canada		
Natural gas revenue	$ 63,828	$ —
Avg. Price ($/Mcf)	$ 1.22	$ —
Natural gas liquids revenue	$ 82,479	$ —
Avg. Price ($/Bbl)	$ 23.01	$ —
Oil and condensate revenue	$ 840,969	$ 116,163
Avg. Price ($/Bbl)	$ 55.84	$ 46.04
Total Canada Revenues	**$ 987,276**	**$ 116,163**
Total Company Revenues	**$ 51,587,556**	**$ 31,522,775**

Gathering System Operations

Epsilon Energy USA is the 100% owner of Epsilon Midstream, which owns a 35% undivided interest in the Auburn GGS, located in Susquehanna County, Pennsylvania, with partners Appalachia Midstream Services, LLC (43.875%) and Equinor Pipelines, LLC (21.125%). The Anchor Shippers, consisting of Epsilon Energy USA, Equinor USA Onshore Properties, Inc., and Expand Energy Corporation, dedicated approximately 18,000 mineral acres to the Auburn GGS on January 1, 2012 for an initial term of 15 years under an Anchor Shipper Gas Gathering Agreement for northern Pennsylvania whereby the Auburn GGS owners received a fixed percentage rate of return on the total capital invested in the construction of the system.

On May 17, 2024, Epsilon Energy USA executed a new Anchor Shipper Gas Gathering Agreement for northern Pennsylvania (the "ASGGA”) with operator Appalachia Midstream Services, LLC for a primary term of ten years and an effective date of January 1, 2024. Epsilon Energy USA simultaneously terminated the prior agreement. The new ASGGA establishes fixed gathering, compression and cross-flow rates for all shippers on each system into which Epsilon produces natural gas. These rates will be adjusted annually by the Consumer Price Index for All Urban Consumers ("CPI-U") commencing January 2025. Notably, the gathering rates in Auburn GGS, Rome GGS & Overfield GGS will no longer be subject to a cost-of-service redetermination annually; however, acreage dedications, service priority levels, required shipper approvals and shipper voting procedures are all substantially consistent with the prior agreement.

Revenues from the Auburn GGS are earned primarily from the Anchor Shippers with well pads located within the Auburn GGS system boundary. Revenues are also earned when natural gas originating in adjacent gathering systems flow into the Auburn GGS ("cross-flow gas") to the compression facility, and then to the delivery meter at Tennessee Gas Pipeline. The relative mix of Anchor Shipper gas and cross-flow gas is critical to the revenue and earnings of the Auburn GGS because the cross-flow gathering rate is only 25% of the Anchor Shipper rate. Shippers cross-flowing gas must pay the gathering rate of the originating gathering system plus 25% of the Auburn GGS gathering rate. The purpose of the reduced rate is to attract additional volumes that require delivery to Tennessee Gas Pipeline when there is spare capacity at the Auburn compression facility, or the "Auburn CF".

The Auburn GGS consists of approximately 44 miles of gathering pipelines, a small auxiliary compression facility and a main compression facility with three dehydration units and three Caterpillar 3612 compression units. At inception, the capacity of the Auburn CF was approximately 330,000 Mcf per day at a design suction pressure of 800 psig. The design suction pressure was subsequently reduced to 550 psig in June 2020 at the request of the Anchor Shippers. This request served to minimize throughput decline during a period of low pricing in which the drilling of new wells was undesirable. The design suction pressure at the Auburn compression facility was reduced further from 550 psig to 450 psig in January 2025 and from 450 psig to 400 psig in December 2025. Operating at the lower design suction pressure has the benefit of reducing hydrate occurrences in the system which can pose an operational hazard. The current system capacity of the Auburn CF at this lower design pressure is approximately 127,000 Mcf per day. The facility capacity could be increased again, if required, by either adding compression units or increasing the design suction pressure.

The Auburn CF delivers processed natural gas into the Tennessee Gas Pipeline at the Shoemaker Dehy receipt meter. The Auburn GGS is connected with the adjacent Rome GGS, which allows for the receipt of additional natural gas to maximize utilization of the Auburn CF and Tennessee Gas Pipeline meter capacity.

During the years ended December 31, 2025 and 2024, the Auburn GGS delivered 40.5 Bcf and 36.9 Bcf respectively, of natural gas, or 111,000 Mcf per day and 101,000 Mcf per day.

Gathering system revenues derived from Epsilon's production, which have been eliminated from total gathering system revenues ("elimination entry"), amounted to $1.9 million and $1.1 million for the years ended December 31, 2025 and 2024, respectively.

Proved Reserves

Per our reserve reports prepared by independent petroleum consultants, DeGolyer and MacNaughton and Cawley, Gillespie & Associates (Powder River Basin assets only), our estimated proved reserves as of December 31, 2025, are summarized in the table below. See Risk Factors for information relating to the uncertainties surrounding these reserve categories.

	Natural Gas MMcf	Natural Gas Liquids MBbl	Oil and Other Liquids MBbl	Total MMcfe
Proved developed reserves	75,849	1,599	4,000	109,444
Proved undeveloped reserves	10,523	753	5,259	46,593
Total Proved Reserves at December 31, 2025	86,372	2,352	9,259	156,037
Changes in Total Proved Undeveloped Reserves				
Proved undeveloped reserves at December 31, 2024	12,550	387	725	19,225
Revisions of previous estimates	(4,949)	(85)	(194)	(6,628)
Acquisitions	4,609	639	4,933	38,041
Divestitures	(1,521)	(134)	(65)	(2,715)
Transfers to proved developed	(166)	(54)	(140)	(1,330)
Proved undeveloped reserves at December 31, 2025	10,523	753	5,259	46,593

Revisions to previous estimates for total proved undeveloped reserves for 2025 include reductions of 6,340 MMcfe related to changes to the previously adopted development plan and reductions of 269 MMcfe related to technical revisions and reductions of 19 MMcfe related to commodity pricing. Acquisitions of 38,041 MMcfe relate to reserves acquired in Wyoming from the Peak acquisition. Divestitures of 2,715 MMcfe relate to the selling of all interests in Oklahoma. Transfers to Proved Developed Reserves of 1,330 MMcfe relates to the development of wells in the Permian Basin.

Our development capital spending to convert Proved Undeveloped Reserves to Proved Developed Reserves for the periods indicated is as follows:

- In 2025 in Pennsylvania, 4 gross (0.24) wells were turned on line in January 2025 and 3 gross (0.04) wells were turned on line in March 2025.
- In 2024 in Pennsylvania, we drilled 3 gross (0.04 net) wells and participated in the completion of 10 gross (0.82 net) wells. The three wells turned on line in October 2024.
- In 2025 in the Permian Basin, the Company participated in the drilling and completion of 1 gross (.25 net) well. This well went into production in Texas in July 2025.
- In 2024 in the Permian Basin, the Company participated in the drilling and completion of 2 gross (0.5 net) wells. These wells went into production in May 2024 and July 2024.
- In 2025 in Canada, we participated in the completion of 2 gross (0.5 net) wells. The two wells turned on line in March 2025.
- In 2024 in Canada, we participated in the drilling and completion of 2 gross (0.5 net) wells. One well was put on production in September 2024. One well was deemed non-commercial.
- In 2025 and 2024 in Oklahoma, there was no development activity. The Company sold all of its assets in Oklahoma in December 2025.

Internal Controls Over Reserves Estimation Process and Qualifications of Technical Persons with Oversight for the Company's Overall Reserve Estimation Process

Our policies regarding internal controls over reserve estimates require reserves to be prepared by an independent engineering firm under the supervision of our Chief Operating Officer, and to be in compliance with generally accepted geologic, petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. The corporate staff interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting and marketing employees to obtain the necessary data for the reserves estimation process. We provide our engineering firm with property interests, production, capital budgets, current operating costs, current production prices and other information. This information is reviewed by our Chief Operating Officer to ensure accuracy and completeness of the data prior to submission to our independent engineering firm. Reserves are reviewed and approved internally by our Chief Operating Officer on a semi-annual basis. Our Chief Operating Officer holds a Bachelor of Science degree in Petroleum Engineering and received a Master's Degree of Business Administration. He has over 30 years of experience in upstream exploration and production, and has managed all phases of drilling, completions, production and field operations.

The reserve information in this report is based on estimates prepared by DeGolyer and MacNaughton and Cawley, Gillespie & Associates, our independent petroleum consultants. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4-10(a) (1)-(32) of Regulation S-X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

The person responsible for preparing the DeGolyer and MacNaughton reserve report, Dilhan Ilk, is a Registered Professional Engineer (No.139334) in the State of Texas and a Senior Vice President of the firm. Dr. Ilk graduated from Texas A&M University with a Doctor in Philosophy degree in Petroleum Engineering, is a member of the Society of Petroleum Engineers, and has in excess of 15 years of experience in oil and gas reservoir studies and reserves evaluations.

Cawley Gillespie & Associates is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. The lead evaluator that prepared the reserve report was Zane Meekins, P.E., Executive Vice President at Cawley Gillespie.

Mr. Meekins has been with Cawley Gillespie since 1989 and graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins is a State of Texas registered professional engineer (License #71055) and a member of the Society of Petroleum Evaluation Engineers and the Society of Petroleum Engineers. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Mr. Meekins is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Marketing and Major Customers

Natural gas marketing is competitive in northeast Pennsylvania because of the limited interstate transportation capacity and ample natural gas supply. We do not currently own any firm transportation on interstate pipelines that would enable us to diversify our natural gas sales to downstream locations. As a result, all of our Pennsylvania gas sales occur in Zone 4 of the Tennessee Gas Pipeline at the Shoemaker Dehy meter, which is the receipt point from the Auburn CF.

Epsilon uses a third-party service, ARM Energy Management LLC ("ARM") for its Pennsylvania natural gas marketing. In this capacity, ARM is responsible for carrying out marketing activities such as submission of nominations, receipt of payments, and submission of invoices.

For the year ended December 31, 2025, we sold natural gas through ARM to 34 unique customers. SWN Energy Services Company, LLC accounted for 10% or more of our total revenue. For the year ended December 31, 2024, we sold natural gas through ARM to 33 unique customers. Direct Energy Business Marketing, LLC and EQT Energy, LLC each accounted for 10% or more of our total revenue.

In Wyoming, for our operated oil and gas production, two customers accounted for 95.7% of our total revenues.

Geographic Locations of Operations

Approximately 67% and 50% of our revenue during fiscal years 2025 and 2024, respectively, was derived from natural gas production and gathering system revenues in the state of Pennsylvania. Approximately 19% and 40% of our revenue during fiscal years 2025 and 2024, respectively, was derived from oil, natural gas, and natural gas liquids revenues in the state of Texas. In November 2025, the Company completed the acquisition of oil and gas assets in the Powder River Basin, Wyoming which will materially increase the geographic diversification of our revenues going forward and could provide enhanced flexibility to respond to market conditions by allocating capital across multiple basins and commodities.

However, the Company is still subject to geographic concentration, and we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas.

Competition

It is not uncommon in the oil and natural gas industry to experience shortages of drilling and completion rigs, equipment, pipe, services, and personnel, which can cause both delays in development drilling activities and significant cost increases. We are exposed to the risk of industry competition for drilling rigs, completion rigs and availability of related equipment and services, among other goods and services required in our business.

Employees

As of December 31, 2025, we had twenty-seven full-time employees (including executive officers) in Texas, Colorado, and Wyoming. None of our employees are subject to a collective bargaining agreement or represented by a union.

The foundation of our Company is our employees and our success begins with a values-driven culture and commitment to developing a skilled, agile, diverse and engaged workforce where every employee understands that they can and do make a difference. Advancing a safe, ethical, inclusive and diverse culture creates an environment that attracts and retains the high-performing workforce needed to successfully execute our strategy.

We continue to foster a culture that embraces inclusion and diversity and encourages collaboration. Our core values include inclusion and diversity, and we believe in equity and the value and voice of every employee.

Regulation

Environmental Regulation

Epsilon is subject to various federal, state and local laws and regulations governing the handling, management, disposal and discharge of materials into the environment or otherwise relating to the protection of human health, safety and the environment. Numerous governmental agencies, such as the U.S. Environmental Protection Agency ("EPA”), or the Bureau of Land Management ("BLM”) issue regulations to implement and enforce such laws, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or that may result in injunctive relief for failure to comply. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentrations of various substances, including water and waste, that can be released into the environment;
- limit or prohibit activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

Compliance with environmental laws and regulations increases Epsilon's overall cost of business, but has not had, to date, a material adverse effect on Epsilon's operations, financial condition or results of operations. In addition, it is not anticipated, based on current laws and regulations, that Epsilon will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, given that such laws and regulations are subject to change, Epsilon is unable to predict the ultimate cost of compliance or the ultimate effect on Epsilon's operations, financial condition and results of operations.

Climate Change

There is consensus in the international scientific community that increasing concentrations of greenhouse gas emissions ("GHG") in the atmosphere will produce changes to global, as well as local, climate. Scientists project that increased concentrations of GHGs will cause more frequent, and more powerful storms, droughts, floods and other climatic events. If such effects were to occur, our development and production operations, as well as operations of our third-party providers and customers, could be adversely affected. To date, we have not developed a comprehensive plan to address potential impacts of climate change on our operations and there can be no assurance that any such impacts would not have an adverse effect on our financial condition and results of operations.

Attempts to address GHGs, as well as climate change more generally, have taken the form of local, state, national and international proposals. Broadly speaking, examples include cap-and-trade programs, carbon tax proposals, GHG reporting and tracking programs, and regulations that directly limit GHGs from certain sources.

In the United States, federal proposals are rooted in the EPA's "endangerment finding," that was upheld by the Supreme Court. Simply, the EPA has concluded that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment. For example, the EPA adopted regulations that require Prevention of Significant Deterioration ("PSD") construction under Title V operating permit reviews for GHG emissions from certain large stationary sources that constitute major sources of emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards.

Rules requiring the monitoring and reporting of GHG emissions from designated sources in the United States on an annual basis, including, oil and natural gas production facilities and processing, transmission, storage and distribution facilities, which include certain of our operations, have been adopted. The EPA has expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering and boosting facilities.

Federal agencies also have begun directly regulating emissions of methane from natural gas operations. In 2016, the EPA published New Source Performance Standards ("NSPS"), known as Subpart OOOOa, that require certain facilities to reduce methane gas and volatile organic compound emissions. EPA published amendments to those regulations effective September 15, 2020. However, on January 20, 2021, President Biden issued an Executive Order directing EPA to consider suspending, revising or rescinding the September 15, 2020 amendments and also to consider proposing new regulations governing methane and volatile organic compound emissions from existing oil and gas sector operations.

In November 2016, the BLM published a final rule to reduce methane emissions by regulating venting, flaring, and leaking from oil and natural gas operations on public lands. A federal district court vacated much of that rule in October 2020 and that decision is now subject to an appeal.

Internationally, in April 2016, the United States joined other countries in entering into a non-binding agreement in France for nations to limit their GHG emissions through country-determined reduction goals every five years beginning in 2020 (the "Paris Agreement"). Although the Trump Administration subsequently announced plans to withdraw from the Paris Agreement, on January 20, 2021, President Biden issued an Executive Order providing that he was accepting the Paris Agreement on behalf of the United States.

In addition, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations on certain sources of funding for the energy sector. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities.

Epsilon is unable to predict the timing, scope and effect of any currently proposed or future, laws, regulations or treaties regarding climate change and GHG emissions. Any limits on GHG emissions, however, could adversely affect demand for the oil and natural gas that production operators produce, some of whom are our customers, which could thereby reduce demand for our gas gathering services. We are currently unable to calculate or predict the direct and indirect costs of GHG or climate change related laws, regulations and treaties, and accordingly, we cannot assure you that any such efforts will not have a material impact on our operations, financial condition and results.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices and has finalized a study of the potential environmental impacts of hydraulic fracturing activities. In 2014, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act of 1976 requesting comments related to disclosure for hydraulic fracturing chemicals. The Department of the Interior had released final regulations governing hydraulic fracturing on federal and Native American oil and natural gas leases which require lessees to file for approval of well stimulation work before commencement of operations and require well operators to disclose the trade names and purposes of additives used in the fracturing fluids. However, in December 2017, the BLM published a final rule rescinding the March 26, 2015 rule ("BLM 2015 Rule"), entitled "Natural gas and oil; Hydraulic Fracturing on Federal and Indian Lands." The primary purposes of the BLM 2015 Rule were to ensure that wells were constructed so as to protect water supplies, to ensure environmentally responsible management of fluids displaced by fracturing, and to provide public disclosure of chemicals used in fracturing operations. The net effect of the December 2017 rule making is to return the affected sections of the Code of Federal Regulations to the language that existed before the BLM's 2015 Rule. In addition, legislation has from time to time been introduced, but not adopted, in Congress to provide for additional federal regulation of hydraulic fracturing and to require additional disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances.

Epsilon is unable to predict the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing in the United States, but there can be no assurance that the direct and indirect costs of such laws and regulations (if enacted) would not materially and adversely affect Epsilon's operations, financial condition and results of operations.

Gathering System Regulation

Regulation of gathering facilities may affect certain aspects of Epsilon's business and the market for Epsilon's services. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the Federal Energy Regulatory Commission, or the FERC. The FERC regulates interstate natural gas transportation rates, terms and conditions of service, which affects the marketing of natural gas produced by Epsilon, as well as the revenues received for sales of Epsilon's natural gas.

The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or the NGA, and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation, gathering, and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the U.S. Congress and by FERC regulations.

Market for Our Common Equity and Related Stockholder Matters

Market Information. Commencing on February 19, 2019, the common shares of the Company trade on the NASDAQ Global Market with the ticker symbol "EPSN." The last reported sales price of our common shares on the NASDAQ Global Market on March 23, 2026 was $6.00 per share.

Shareholders. We had approximately 2,000 shareholders of record as of March 1, 2026.

Dividends. Epsilon made aggregate quarterly distributions of $6.0 million ($0.25 per share) during the year ended December 31, 2025. The dividend is well supported and the Company intends to maintain it going forward, subject to quarterly approval by the Board.

Securities Authorized for Issuance under Equity Incentive Plans.

The following tables set out the number of common shares available to be issued upon exercise of outstanding securities and the changes to the securities outstanding for the year pursuant to our equity compensation plans and the weighted average exercise price of outstanding securities for the periods indicated:

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans (excluding shares in column (a))
Common shares under 2020 Equity Incentive Plan	781,792	$ 5.15	140,637

At December 31, 2025, under the 2020 Equity Incentive Plan (the "2020 Plan") (See Note 7, "Shareholders' Equity" of the Notes to the Consolidated Financial Statements), we are authorized to issue 2,000,000 common shares to employees and directors of the Company. As of that date, we had 1,859,363 common shares granted under the 2020 Plan.

The following table sets out the number of time restricted common shares available to be issued upon vesting over the next three years and the changes during the year pursuant to our share compensation plans and the weighted average market price at date of issue for outstanding shares for the periods indicated:

	As of December 31, 2025		As of December 31, 2024	
	Number of Shares Outstanding	Weighted Average Grant Date Market Price	Number of Shares Outstanding	Weighted Average Grant Date Market Price
Balance non-vested Restricted Stock at beginning of period	560,970	$ 5.77	491,536	$ 6.00
Granted	488,283	4.77	300,052	5.97
Vested	(267,461)	5.60	(230,618)	5.65
Balance non-vested Restricted Stock at end of period	781,792	$ 5.15	560,970	$ 5.77

Recent Developments

Business Combination

On November 14, 2025, Epsilon acquired Peak Exploration & Production LLC and Peak BLM Lease LLC and their subsidiaries (together, "Peak") for total consideration of $88.5 million consisting of 1) issuance of 5,681,489 common shares valued at $27.6 million, 2) contingent consideration of up to 2,500,000 common shares valued at $10.6 million, and the settlement of $50.3 million of debt. The contingent consideration was settled on November 19, 2025, through the issuance of 2,234,847 common shares for $10.6 million. The acquired assets primarily include operated and non-operated production and leasehold interests in the core of the Powder River Basin in Wyoming. The acquired Proved Reserves include 16.8 Bcf of natural gas, 8.2 MMBbls of oil, and 2.0 MMBbls of natural gas liquids, according to the report by Cawley Gillespie & Associates as of December 31, 2025. As part of the acquisition, the Company added 17 full-time employees from Peak.

The results of operations attributable to the Peak acquisition have been included in the Company's consolidated financial statements as of the closing date of the acquisition.

Asset Sale

On December 11, 2025, Epsilon divested Dewey Energy Holdings, LLC, a wholly owned subsidiary of the Company to an undisclosed private buyer for $2.5 million. The assets sold included approximately 964 Mcfe/d (60% natural gas) of production (Q4 2025 figure) and approximately 6,400 net deep acres and 2,200 net shallow acres of leasehold, all located in Dewey County, Oklahoma.

Credit Facility

On October 10, 2025, the Company closed a new senior secured reserve based revolving credit facility with Frost Bank as administrative agent and Frost Bank and Texas Capital Bank as lenders. This replaced the Company's previous credit facility. As of December 31, 2025, the borrowing base was $80 million, supported by the Company's producing reserves and is subject to semi-annual redeterminations with a maturity date of October 10, 2029. Interest will be charged at the 3-month Term SOFR rate plus a margin of 3-4% (depending on facility utilization), payable quarterly. The facility is secured by the assets of the Company's Epsilon Energy USA subsidiary. During March 2026, the Company made a $5 million repayment on the outstanding credit facility. The current balance as of March 25, 2026 is $45.5 million.

ITEM 1A. RISK FACTORS.

You should carefully consider the risks and uncertainties described below, together with all of the other information and risks included in, or incorporated by reference into this report, including our consolidated financial statements and the related notes thereto, before making any financial decisions relating to Epsilon.

Risks Related to Oil and Natural Gas Reserves

Our business is dependent on oil and natural gas prices, and any fluctuations or decreases in such prices could adversely affect our results of operations and financial condition.

Revenues, profitability, liquidity, ability to access capital and future growth prospects are highly dependent on the prices received for oil and natural gas. The prices of these commodities are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, and this volatility may continue in the future. The volatility of the energy markets generally makes it extremely difficult to predict future oil and natural gas price movements. Also, prices for oil and prices for natural gas do not necessarily move in tandem. Declines in oil or natural gas prices would not only reduce revenue but could also reduce the amount of oil and natural gas that can be economically produced and therefore potentially lower natural gas and oil reserve quantities. If the oil and natural gas industry experiences low prices, we may, among other things, be unable to meet all our financial obligations or make planned expenditures.

Substantial and extended declines in oil and natural gas prices may result in impairments of proved natural gas and oil properties or undeveloped acreage and may materially and adversely affect our future business, financial condition, cash flows, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital expenditures, spending will be required to be reduced, assets could be sold or funds may be borrowed to fund any such shortfall.

Our long term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves, the failure of which could result in under-use of capital and in losses.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves that we may have at any particular time and the production from those reserves will decline over time as those reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. We cannot assure you that we will be able to locate and continue to locate satisfactory properties for acquisition or participation. Moreover, if we do identify such acquisitions or participations, we may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. We cannot assure you that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations, and the loss of the ability to use hydraulic fracturing (see risk factor regarding government legislation). Losses resulting from the occurrence of any of these risks could have a material adverse effect on our future results of operations, liquidity and financial condition.

Our reserve estimates may be inaccurate, and future net cash flows as well as our ability to replace any reserves are uncertain.

There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom, including many factors beyond our control. The reserve and associated cash flow information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions such as historical oil and natural gas prices, production levels, capital expenditures, operating and development costs, the effects of regulation, the accuracy and reliability of the underlying engineering and geologic data, and the availability of funds; all of which may vary from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom and prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material.

In accordance with applicable securities laws, the technical report on our oil and natural gas reserves prepared by DeGolyer and MacNaughton, independent petroleum consultants, as of December 31, 2025 and 2024 ("DeGolyer Reserve Report”), and the report by Cawley, Gillespie & Associates as of December 31, 2025 ("CGA Reserve Report”), used SEC guideline prices and cost estimates in calculating net cash flows from oil and natural gas reserve quantities included within the report. Actual future net revenue will be affected by other factors such as actual commodity prices, production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and revenues derived therefrom will vary from the estimates contained in the DeGolyer Reserve Report and CGA Reserve Report, and such variations could be material. The DeGolyer Reserve Report and the CGA Reserve Report are based in part on the assumed success of activities that we intend to undertake in future years. The oil and natural gas reserves and estimated cash flows to be derived therefrom contained in these reserve reports will be reduced to the extent that such activities do not achieve the level of success assumed in these reserve reports.

Our future oil and natural gas reserves, production, and derived cash flows are highly dependent on our successfully acquiring or discovering and developing new reserves. Without the continual addition of new reserves, any of our existing reserves and their production will decline as such reserves are exploited. A future increase in our reserves will depend not only on our ability to develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. There can be no assurance that our future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Risks Related to Stage of Development, Structure and Capital Resources

If there is a sustained economic downturn or recession in the United States or globally, natural gas and oil prices may fall and may become and remain depressed for a long period of time, which may adversely affect our results of operations. We may be unable to obtain additional capital required to implement our business plan, which could restrict our ability to sustain or grow our business.

Operations could also be adversely affected by general economic downturns or limitations on spending. An economic downturn and uncertainty may have a negative impact on our business. During 2025 and 2024, there was tremendous volatility in prices and available financing for oil and gas projects. There can be no assurance that we will be able to access capital markets to provide funding for future operations that would require additional capital beyond our current existing available capital on terms acceptable to us.

Substantial capital, which may not be available to us in the future, is required to replace and grow reserves.

We anticipate making capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If our revenues or reserves decline, we may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements, or for other corporate purposes. If debt or equity financing is available, there is no assurance that it will be on terms acceptable to us. Moreover, future activities may require us to alter our capitalization significantly. Additional capital raised through the issuance of common shares or other securities convertible into common shares may result in a change of control and dilution to shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our financial condition and results of operations.

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times. From time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities, or reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt, equity financing or the proceeds from the sale of a portion or all of our interest in one or more projects will be available to meet these requirements or available on terms acceptable to us.

The borrowing base under our credit facility may be reduced in light of commodity price declines or reserve changes, which could limit us in the future.

Lower commodity volumes and prices may reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of our lenders primarily based on the collateral value of our Proved Developed Reserves that have been mortgaged to the lenders, and is subject to semiannual redeterminations. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to immediately repay a portion of the debt outstanding.

The terms of our revolving credit facility may restrict our operations, particularly our ability to respond to changes or to take certain actions.

The agreement that governs our revolving credit facility contains covenants that impose operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long term best interest, including restrictions on our ability, subject to satisfaction of certain conditions, to incur additional indebtedness, sell assets, enter into transactions with affiliates, and enter into or refrain from entering into hedging contracts.

In addition, the restrictive covenants in our revolving credit facility require us to maintain specified financial ratios and satisfy other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we may be unable to meet them.

A breach of the covenants or restrictions under the contract that governs our revolving credit facility could result in an event of default under the applicable indebtedness. Such a default may allow the creditors to accelerate the repayment of the outstanding indebtedness. In the event our lenders accelerate the repayment of our borrowings, we may not have sufficient resources to repay that indebtedness.

Depending on forces outside our control, we may need to allocate our available capital in ways that we did not anticipate.

Because of the volatile nature of the oil and natural gas industry, we regularly review our budgets in light of past results and future opportunities that may become available to us. In addition, our ability to carry out operations may depend upon the decisions of other working interest owners in our properties. Accordingly, while we anticipate that we will have the ability to spend the funds available to us, there may be circumstances where, for sound business reasons, a reallocation of funds may be prudent.

We may issue debt to acquire assets or for working capital.

From time to time, we may enter into transactions to acquire assets or shares of other companies. These transactions may be financed partially or wholly with debt, which may increase our debt levels. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favorable terms. Neither our articles of incorporation nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Our potential lenders will likely require security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default, such as bankruptcy, these lenders may foreclose on or sell our properties. The proceeds of any such sale would be applied to satisfy amounts owed to our lenders and other creditors, and only the remainder, if any, would be available to us.

Future equity transactions could result in dilution to existing stockholders.

We may make future acquisitions or enter into financing or other transactions involving the issuance of securities, which may be dilutive to existing security holders.

Competition in the natural gas and oil industry is intense, which may hinder our ability, and the ability of our third-party operating partners, to contract for drilling equipment, and we may not be able to control the scheduling and activities of contracted drilling equipment.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and our third-party operating partners and may delay exploration and development activities. Past industry conditions have led to periods of extreme shortages of drilling equipment in certain areas of the United States. On the oil and natural gas properties that we do not operate, we will be dependent on such operators for the timing of activities related to such properties and may be largely unable to direct or control the activities of the operators.

Results of our drilling are uncertain, and we may not be able to generate high returns.

Our operations involve utilizing the latest drilling and completion techniques in order to maximize cumulative recoveries and generate high returns. If drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, or if crude oil and natural gas prices decline, the return on our investment in these areas may not be as attractive as anticipated. Further, less than anticipated results in developments could incur material write downs of our oil and natural gas properties and the value of undeveloped acreage could decline in the future.

Extensive government legislation and regulatory initiatives could increase costs and impose burdensome operating restrictions that may cause operational delays.

Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into deep rock formations to stimulate oil or natural gas production, is often used in the completion of unconventional oil and natural gas wells. Currently, hydraulic fracturing is primarily regulated in the United States at the state level, which generally focuses on regulation of well design, pressure testing, and other operating practices.

However, some states and local jurisdictions across the United States, such as the State of New York, have begun adopting more restrictive regulation. Some members of the U.S. Congress and the EPA are studying environmental contamination related to hydraulic fracturing and the impact of fracturing on public health. In March 2015, the U.S. Congress introduced legislation to regulate hydraulic fracturing and require disclosure of the chemicals used in the hydraulic fracturing process, and may implement more stringent regulations in the future. Additionally, some states, such as the State of New York, have adopted, and others are considering, regulations that could restrict hydraulic fracturing. The ultimate status of such regulation is currently unknown. Any federal or state legislative or regulatory changes with respect to hydraulic fracturing could cause us to incur substantial compliance costs or result in operational delays, and the consequences of any failure to comply by us or our third-party operating partners could have a material adverse effect on our financial condition and results of operations.

Our corporate structure could result in incremental tax burden in certain circumstances.

Epsilon Energy Ltd. is an Alberta company. Epsilon Energy USA Inc. (Ohio corporation) may be a U.S. real property holding corporation (a "USRPHC") for U.S. federal income tax purposes if it is determined, at any time, that the fair market value of its assets that consist of "United States real property interests," as defined in the Internal Revenue Code, and applicable Treasury regulations, constitute at least 50% of the combined fair market value of our real property interests and other business assets. If Epsilon Energy USA Inc. were a USRPHC, then Epsilon Energy Ltd.'s investment in Epsilon Energy USA Inc. would be a United States Real Property Interest (USRPI) for US federal tax purposes. As a result, the Foreign Investment in Real Property Tax Act, or "FIRPTA," would require Epsilon Energy Ltd. to pay U.S. federal income tax at the corporate income tax rates on capital gain distributions made by Epsilon Energy USA Inc. to Epsilon Energy Ltd. Distributions made out of earnings and profits are not expected to be subject to the FIRPTA tax but are subject to U.S. withholding tax.

Our operations are currently geographically concentrated and therefore subject to regional economic, regulatory and capacity risks.

Approximately 67% and 50% of our revenue during fiscal years 2025 and 2024, respectively, was derived from natural gas production and gathering system revenues in the state of Pennsylvania. Approximately 19% and 40% of our revenue during fiscal years 2025 and 2024, respectively, was derived from oil, natural gas, and natural gas liquids revenues in the state of Texas. In November 2025, the Company completed the acquisition of oil and gas assets in the Powder River Basin, Wyoming which could provide the Company the enhanced flexibility to respond to market conditions by allocating capital across multiple basins and commodities.

However, the Company is still subject to geographic concentration and we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas.

Delays in business operations may reduce cash flows and subject us to credit risks.

In addition to the usual delays in payments by purchasers of oil and natural gas to us or to the operators, and the delays by operators in remitting payment to us, payments from these parties may be delayed by restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. In addition, the transition of one operator to another as the result of an operator being bought or sold could cause additional operational delays beyond our control. Any of these delays could reduce the amount of cash flow available for our business in a given period and expose us to additional third-party credit risks.

We depend on the successful acquisition, exploration and development of oil and natural gas properties to develop any future reserves and grow production and revenue in the future, and assessments of our assets may be subject to uncertainty.

Acquisitions of oil and natural gas companies and oil and natural gas assets are typically based on engineering and economic assessments made by independent engineers and our own assessments. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. In particular, the prices of, and markets for, oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on analysis by our internal engineers or reports by a firm of independent engineers that are not the same as the firm that we use for our year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm that we use.

We depend on third-party operators and our key personnel, and competition for experienced technical personnel may negatively affect our operations.

Approximately 50% of our oil and natural gas properties are operated by third-party operators. As such, we will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. The objectives and strategy of those operators may not always be consistent with ours, and we have a limited ability to exercise influence over, and control the risks associated with, operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues from our assets or could increase costs or create liability for the operator's failure to properly maintain the well and facilities and to adhere to applicable safety and environmental standards.

Our success will depend in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse effect on us. We do not have key person insurance in effect for management. The contributions of these individuals to our immediate operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense, and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Certain of our directors are also directors of other companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the Conflicts Committee of our board of directors.

Our leasehold interests are subject to termination or expiration under certain conditions.

Our properties are held in the form of leases and working interests in leases, collectively referred to as "*leasehold interests*." If we or our joint venture partner fails to meet the specific requirement(s) of a particular leasehold interest, the leasehold interest may terminate or expire. There can be no assurance that any of the obligations required to maintain each leasehold interest will be met. The termination or expiration of a particular leasehold interest may have a material adverse effect on our financial condition and results of operations.

We may incur losses as a result of title deficiencies.

Although title reviews will be done according to industry standards before the purchase of most oil and natural gas-producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction in our ownership interest or of the revenue that we receive.

We may be exposed to third-party credit risk, and defaults by third parties could adversely affect us.

We are or may be exposed to third-party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production, derivative counterparties and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations.

We may not be insured against all of the operating risks to which we are exposed.

Our involvement in the exploration for and development of oil and natural gas properties may result in our becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although before drilling we plan to obtain insurance in accordance with industry standards to address certain of these risks, such insurance may not be available, be price prohibitive, or contain limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable, or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks because of the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position and our results of operations.

Risks Related to Commodity Prices, Hedging and Marketing

Natural gas and oil prices fluctuate widely, and low prices for an extended period would likely have a material adverse effect on our business.

Our revenues, profitability and future growth and the carrying value of our oil and natural gas properties are substantially dependent on prevailing prices of oil and natural gas. Our ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and natural gas prices. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States, the Middle East and elsewhere in the world; the actions of OPEC; governmental regulation; political stability in the Middle East and elsewhere; the foreign supply of oil and natural gas; the price of foreign imports; and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. There can be no assurance that recent commodity prices can be sustained over the life of our operations. There is substantial risk that commodity prices may decline in the future, although it is not possible to predict the time or extent of such decline.

Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings that may be available to us are in part determined by our borrowing base. A sustained material decline in prices from historical average prices could reduce our borrowing base, thereby reducing the bank credit available to us, which could require that a portion, or all, of our bank debt be repaid.

Hedging transactions may limit our potential gains or cause us to lose money.

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, we will not benefit from such increases.

We are exposed to risks of loss in the event of nonperformance by our counterparties to our hedging arrangements. Some of our counterparties may be highly leveraged and subject to their own operating and regulatory risks. Despite our analysis, we may experience financial losses in our dealings with these and other parties with whom we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our counterparties could have a material adverse effect on our business, financial condition and results of operations.

Additionally, we may, due to circumstances beyond our control, be put in a position of over hedging. If this occurs, our revenue could be adversely affected due to the necessity of buying oil and natural gas at the current market rate in order to fulfill hedging sales obligations.

Market conditions or operation impediments may hinder our access to natural gas and oil markets or delay our production.

The marketability and price of oil and natural gas that we may produce, acquire or discover will be affected by numerous factors beyond our control. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets. This risk is somewhat mitigated in Pennsylvania by our 35% ownership of a gathering system in northeast Pennsylvania. We may also be affected by extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, and many other aspects of the oil and natural gas business.

We depend upon two significant purchasers for the sale of most of our oil and natural gas production in Wyoming. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

For year ended December 31, 2025, HF Sinclair Refining & Marketing LLC and WGR Operating, LP accounted for approximately 68.4% and 27.3% of our total revenues in Wyoming, respectively, excluding the impact of our commodity derivatives. No other purchaser accounted for more than 10% of our revenue during such periods. We do not have long term contracts with our purchasers but rather we sell the substantial majority of our production under arm's length contracts with terms of 12 months or less, potentially including on a month-to-month basis, to a relatively small number of purchasers. We do not believe that the loss of a single purchaser would materially affect our business because there are numerous other potential purchasers in the area in which we sell our production. However, the loss of any one of these significant purchasers, our ability to sell our production to other purchasers on terms we consider acceptable, the inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation could have a short term impact on our financial condition and results of operations. We cannot assure you that any of our purchasers will continue to do business with us or that we will continue to have ready access to suitable markets for our future production.

Investor sentiment towards climate change, fossil fuels, and sustainability could adversely affect our business and our share price.

There have been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, to promote the divestment of shares of energy companies, as well as to pressure lenders and other financial services companies to limit or curtail activities with energy companies. If these efforts are successful, our stock price and our ability to access capital markets may be negatively impacted.

Members of the investment community are also increasing their focus on sustainability practices, including practices related to GHGs and climate change, in the energy industry. As a result, we may face increasing pressure regarding our sustainability disclosures and practices. Additionally, members of the investment community may screen companies such as ours for sustainability performance before investing in our shares.

We are subject to complex laws and regulations, including environmental regulations that can have a material adverse effect on the cost, manner and feasibility of doing business.

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Our operations may require licenses and permits from various governmental authorities. There can be no assurance that we will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at our projects. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and natural gas companies of similar size.

In Wyoming, we conduct oil and natural gas exploration, development and production activities on federal lands, including lands administered by the BLM and in some cases, United States Forest Service. Operations on federal lands are frequently subject to permitting delays. Operations on these lands are also subject to the National Environmental Policy Act ("NEPA") which requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. While the Company currently has exploration, development and production activities on federal lands, our proposed exploration, development and production activities are expected to include federal mineral interests, which will require the acquisition of governmental permits or authorizations that are subject to the procedural requirements of NEPA. This process has the potential to delay, limit, or increase the cost of the development of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Moreover, depending on the mitigation strategies recommended in Environmental Assessments or Environmental Impact Statements, they could incur added costs, which may be substantial.

Environmental and health and safety risks may adversely affect our business.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills and releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental regulations, we cannot assure you that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects.

We must also conduct our operations in accordance with various laws and regulations concerning occupational safety and health. Currently, we do not foresee expending material amounts to comply with these occupational safety and health laws and regulations. However, since such laws and regulations are frequently changed, we are unable to predict the future effect of these laws and regulations.

Risks Related to Cybersecurity

We may be subject to interruptions or failures in our information technology systems.

We rely on sophisticated information technology systems and infrastructure to support our business, including process control technology. Any of these systems are susceptible to outages due to fire, floods, power loss, telecommunications failures, usage errors by employees, computer viruses, cyberattacks or other security breaches or similar events. The failure of any of our information technology systems may cause disruptions in our operations, which could adversely affect our revenue and profitability.

We are subject to cybersecurity risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

We depend on information technology systems that we manage, and others that are managed by third-party service and equipment providers, to conduct our day-to-day operations, including critical systems, and these systems are subject to risks associated with cyber incidents or attacks, especially originating from countries such as China, Russia, Iran, and North Korea as broadly reported in the media. Our technology systems and networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches. A cyber incident could negatively impact the Company in a number of ways, including but not limited to: (i) remediation costs, such as liability for stolen assets or information and repairs of system damage; (ii) increased cybersecurity protection costs, which may include the costs of making organizational changes, deploying additional personnel and protection technologies, training employees, and engaging third-party experts and consultants; (iii) lost revenue resulting from downtime, operational disruptions, the unauthorized use of proprietary information or the failure to retain or attract customers following an attack; (iv) litigation and legal risks, including regulatory actions by state and federal governmental authorities and non-U.S. authorities and related investigation costs; (v) increased insurance premiums; (vi) reputational damage that adversely affects customer or investor confidence; (vii) the loss, theft, corruption or unauthorized release of intellectual property, proprietary information, customer and vendor data or other critical data and (viii) damage to the Company's competitiveness, stock price, and long term stockholder value. Certain cyber incidents, such as surveillance, may remain undetected for an extended period of time. As the sophistication of cyber incidents continues to evolve, we will likely be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks.

Risks Related to Internal Controls

We are a "smaller reporting company" and as a result of the reduced disclosure requirement applicable to smaller reporting companies, our common shares may be less attractive to investors.

We are a "smaller reporting company" as defined under the Exchange Act, and we will remain a smaller reporting company until the fiscal year following the determination that our voting and non-voting common shares held by non-affiliates is more than $250 million measured on the last business day of our second fiscal quarter and our annual revenue is more than $100 million. Smaller reporting companies are able to provide simplified executive compensation disclosure and have certain other reduced disclosure obligations, including, among other things, being required to provide only two years of audited financial statements and not being required to provide selected financial data, supplemental financial information or risk factors.

We have chosen to take advantage of some, but not all, of the available exemptions for smaller reporting companies. We cannot predict whether investors will find our common shares less attractive if we rely on these exemptions. If some investors find our common shares less attractive as a result, there may be a less active trading market for our common shares and our share price may be more volatile.

If we fail to establish and maintain proper disclosure or internal controls, our ability to produce accurate financial statements and supplemental information or comply with applicable regulations could be impaired.

As we grow, we may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to train and manage our employee base.

We must maintain effective disclosure controls and procedures. We must also maintain effective internal controls over financial reporting or, at the appropriate time, our independent auditors will be unwilling or unable to provide us with an unqualified report on the effectiveness of our internal controls over financial reporting as required by Section 404(b) of the Sarbanes-Oxley Act, once we become subject to those requirements. If we fail to maintain effective controls, investors may lose confidence in our operating results, the price of our common shares could decline and we may be subject to litigation or regulatory enforcement actions.

Risks Related to Gathering System

Because of the natural decline in production from existing wells, our success depends on the Anchor Shippers' economically developing the remaining Marcellus Shale reserves in Pennsylvania.

Our natural gas gathering system is dependent upon the level of production from natural gas wells, from which production will naturally decline over time. In order to maintain or increase throughput levels on our gathering system and compression facility, we must continually develop reserves within the Auburn GGS boundary or obtain new supplies external to the Auburn GGS boundary. Developing reserves within the system boundary is the priority as external natural gas volumes have a contractual gathering rate that is 25% of the Anchor Shipper rate. The primary factors affecting our ability to obtain new supplies of natural gas is the level of successful drilling activity from the Anchor Shippers, of which Epsilon is one, as well as our ability to compete for volumes from successful new wells drilled by third parties proximate to our system. If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on our pipelines and the utilization rates of our compression facility would decline, which could have an adverse effect on our business, results of operations, financial position and cash flows.

Because of the large supply of gas, and limited availability of transportation out of Pennsylvania, our gas is subject to a price differential.

Differential is an energy industry term that refers to the discount or premium received for the sale of a petroleum product at a specific location relative to a nationally recognized sales hub. In Pennsylvania, natural gas is significantly discounted to Henry Hub pricing and the size of the differential can be volatile. Many factors influence the size and duration of differentials including local supply / demand imbalances, seasonal fluctuations in demand, transportation availability and cost, as well as the regulatory environment as it pertains to constructing new transportation pipelines. In northeast Pennsylvania, negative differentials have persisted for many years due to rapid increases in supply as a result of advances in well completion techniques. Despite substantial increases in local demand for natural gas coupled with pipeline expansions, optimizations, and new pipelines that have been brought into service, the natural gas differential in northeast Pennsylvania remains significant. There is no guarantee that future demand or pipeline transportation projects will eliminate this differential, and it will therefore remain a significant risk to demand for transportation service on the Auburn GGS, and therefore Epsilon's revenues and cash flows.

We compete with other operators in our gas gathering energy businesses.

Although the Anchor Shippers have dedicated their acreage and reserves to the Auburn GGS, the Auburn GGS may not be chosen by other producers in these areas to gather and compress the natural gas extracted. We compete with other companies, including co-owners of the Auburn GGS who operate other systems, for any such production from non-Anchor Shippers on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets. Competition in natural gas gathering is based in large part on existing assets, reputation, efficiency, system reliability, gathering system capacity and pricing arrangements. Our key competitors in the natural gas gathering business include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to non-Anchor Shippers we serve, and those producers may also elect to construct proprietary gas gathering systems. A significant increase in competition in the gas gathering industry could have a material adverse effect on our financial position, results of operations and cash flows.

Several of our assets that have been in service for many years may require significant expenditures to maintain them. As a result, our maintenance or repair costs may increase in the future.

Our gathering lines and compression facility are generally long-lived assets, and many of such assets have been in service for many years. The age and condition of our assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our gathering rate and competitive position.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management will not be able to completely eliminate such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Generally, our customers are rated investment grade, are otherwise considered creditworthy, or may be required to make prepayments or provide security to satisfy credit concerns. However, our credit procedures and policies cannot completely eliminate customer and counterparty credit risk. Our customers and counterparties include natural gas producers whose creditworthiness may be suddenly and disparately impacted by, among other factors, commodity price volatility, deteriorating energy market conditions, and public and regulatory opposition to energy producing activities. In a low commodity price environment certain of our customers could be negatively impacted, causing them significant economic stress including, in some cases, to file for bankruptcy protection or to renegotiate contracts. To the extent one or more of our key customers commences bankruptcy proceedings, our contracts with the customers may be subject to rejection under applicable provisions of the United States Bankruptcy Code, or may be renegotiated. Further, during any such bankruptcy proceeding, prior to assumption, rejection or renegotiation of such contracts, the bankruptcy court may temporarily authorize the payment of value for our services less than contractually required, which could have a material adverse effect on our business, financial condition, results of operations, and cash flows. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties or otherwise do not take or are unable to take sufficient mitigating actions, including obtaining sufficient collateral, deterioration in their creditworthiness, and any resulting increase in nonpayment and/or nonperformance by them could cause us to write down or write off accounts receivable. Such write downs or write offs could negatively affect our operating results in the periods in which they occur, and, if significant, could have a material adverse effect on our business, results of operations, cash flows, and financial condition.

Prices for natural gas in northeast Pennsylvania are volatile and are subject to significant discounts from pricing at Henry Hub. This discount and volatility has and could continue to adversely affect our financial results, cash flows, access to capital and ability to maintain our existing businesses.

Our revenues, operating results, and future rate of growth depend primarily upon the price of natural gas in northeast Pennsylvania which is currently volatile and significantly discounted to natural gas at Henry Hub due to insufficient interstate pipeline capacity out of the region. This volatility and discount has adversely impacted reserve development in the past, and could do so again in the future. A slowing pace of or complete halt to the development of Anchor Shipper reserves will impact our financial results, cash flows, and access to capital.

The financial condition of our natural gas gathering businesses is dependent on the continued availability of natural gas supplies and demand for those supplies in the markets we serve.

Our ability to expand our natural gas gathering business primarily depends on the level of drilling and production by the Anchor Shippers. Production from existing wells with access to our gathering systems will naturally decline over time. The amount of natural gas reserves underlying these existing wells may also be less than anticipated, and the rate at which production from these reserves declines may be greater than anticipated. We do not obtain independent evaluations of the third-party natural gas reserves flowing into our systems and compression facilities. Demand for our services is dependent on the demand for gas in the markets we serve. Alternative fuel sources such as electricity, coal, fuel oils, or nuclear energy could reduce demand for natural gas in our markets and have an adverse effect on our business. A failure to obtain access to sufficient natural gas supplies or a reduction in demand for our services in the markets we serve could result in impairments of our assets and have a material adverse effect on our business, financial condition, results of operations, and cash flows.

Our operations are subject to operational hazards and unforeseen interruptions.

There are operational risks associated with gathering and compression of natural gas, including:

- Hurricanes, tornadoes, floods, extreme weather conditions and other natural disasters;
- Aging infrastructure and mechanical problems;

- Damages to pipelines and pipeline blockages or other pipeline interruptions;
- Uncontrolled releases of natural gas, brine, or industrial chemicals;
- Operator error;
- Damage caused by third-party activity, such as operation of construction equipment;
- Pollution and other environmental risks;
- Fires, explosions, craterings, and blowouts; and
- Terrorist attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial financial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers.

Risks Related to Our Business Combination

We may be unable to successfully integrate acquired businesses, which could adversely affect our operations and financial results. The success of the acquisition depends, in part, on our ability to realize anticipated synergies and integrate the acquired assets, personnel and systems with those of the Company. Integration efforts may be complex, time-consuming, and costly, and may include consolidating systems, aligning accounting processes, retaining key personnel, and harmonizing corporate cultures.

We may encounter difficulties in integrating information technology systems, internal controls over financial reporting, and operational processes, which could result in delays, increased expenses, or disruptions to our business. In addition, we may fail to retain key employees, customers, or suppliers of the acquired business. If we are unable to successfully integrate acquired businesses or achieve expected synergies within anticipated timeframes, our financial condition, results of operations, and cash flows could be materially adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 1C. CYBERSECURITY

Risk Management and Strategy

The Company considers cybersecurity risks as part of our overall risk management process. The management team works closely with our IT consultants and IT auditors to ensure potential risks are mitigated within our systems.

The Company engages a third-party IT consulting firm and conducts an annual IT audit to test our risk management processes.

The Company, together with our IT consultants and auditors, has processes that thoroughly vet third-party service providers, continuously monitoring to ensure compliance with our cybersecurity standards.

The Company has not encountered cybersecurity threats that have materially impacted our business or operations.

Governance

The Company's Board of Directors is aware of the impact of potential cybersecurity threats and stays in close contact with management in case a threat is identified.

The Audit Committee of the Board of Directors is the primary governing body that is tasked with the evaluation and confirmation of the Company's cybersecurity threat mitigation processes. More specifically, they review the Company's annual IT audits and discuss any potential threats in quarterly meetings.

The Chief Financial Officer, Chief Operating Officer, Controller, Senior Vice Presidents and Director – Finance are all involved in communications with our IT consultants and auditors. The Chief Financial Officer notifies the Audit Committee and Chief Executive Officer of any cybersecurity threats.

ITEM 2. PROPERTIES.

The information required by Item 2 is contained in '*'Item 1. Business – Properties.*"

ITEM 3. LEGAL PROCEEDINGS.

In 2025, Peak Powder River Resources LLC ("PPRR"), a Subsidiary of Peak Exploration & Production LLC ("Peak E&P") filed a lawsuit against a contractor regarding alleged non-performance while running casing in a well in Wyoming. The Company is seeking damages due to its inability to complete the Leavitt Fed 2-9-4MH well. PPRR is in the process of scheduling arbitration

PPRR and Peak Powder River Acquisitions ("PPRA"), a subsidiary of Peak BLM Lease LLC (Peak BLM"), has intervened as a defendant-intervenor in litigation challenging BLM's issuance of federal oil and gas leases acquired by the Company in 2017, 2018, and 2020. Plaintiffs allege deficiencies in BLM's environmental review under NEPA. The Company intervened to protect its leasehold interests. Management does not believe the outcome will have a material adverse effect on the Company's financial position.

Between September 30, 2025 and October 28, 2025, we received multiple demand letters on behalf of purported Epsilon stockholders (the "Demands"). The Demands primarily alleged that the Preliminary Proxy Statement filed on September 19, 2025 or the Definitive Proxy Statement filed on October 10, 2025, as applicable, failed to disclose certain material information with respect to the acquisition of Peak Exploration and Production, LLC, and Peak BLM Lease LLC.

On October 16, 2025, we received a copy of a complaint filed against Epsilon and certain members of Epsilon's Board of Directors in the Supreme Court of the State of New York, County of New York, on behalf of purported Epsilon stockholder Anthony Morgan (the "Morgan Complaint"). On October 17, 2025, we received a copy of a complaint filed against Epsilon and certain members of Epsilon's Board of Directors in the Supreme Court of the State of New York, County of New York, on behalf of purported Epsilon stockholder Richard Lawrence (the "Lawrence Complaint," and together with the Morgan Complaint, the "Complaints").

The Complaints allege, among other things, that Epsilon and the other named defendants (the "Epsilon Defendants") violated New York common law based on claims of negligence, negligent misrepresentation and concealment. Specifically, the Complaints allege that the Preliminary Proxy Statement or the Definitive Proxy Statement, as applicable, failed to disclose, among other things, certain details regarding the background of the Transactions. Among other remedies, the Complaints sought an injunction against consummating the Transactions, rescission or actual and punitive damages if the Transactions are consummated, costs and attorneys' fees. To date, we have not been served with the Complaints, and the Plaintiffs have not taken any additional steps in furtherance of prosecuting the Complaints.

While we believe that the disclosures set forth in the Preliminary Proxy Statement and the Definitive Proxy Statement comply fully with applicable law, to moot certain of the claims made in the Demands and Complaints, to avoid nuisance and potential expense and delay, we voluntarily supplemented the Definitive Proxy Statement with certain disclosures in our Supplemental Disclosures to Definitive Proxy Statement filed on October 31, 2025. Nothing in our Supplemental Disclosures was an admission of the legal necessity or materiality under applicable law of any of the disclosures set forth in the Preliminary Proxy Statement or the Definitive Proxy Statement. To the contrary, we deny all allegations in the Demands and Complaints that any additional disclosure was required.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

The information required by Item 201 of Regulation S-K is contained in ''*Item 1. Business*.''

On February 18, 2026, the Board authorized a new share repurchase program of up to 3,014,986 common shares, representing 10% of the outstanding common shares of the Company at such time, for an aggregate purchase price of not more than US $15.0 million. The program is pursuant to a normal course issuer bid and conducted in accordance with Rule 10b-18 under the Exchange Act. The program commenced on February 19, 2026 and is set to expire February 18, 2027, unless the maximum amount of common shares is purchased before then or the Board approves earlier termination.

On February 12, 2025, the Board authorized a new share repurchase program of up to 2,200,876 common shares, representing 10% of the outstanding common shares of the Company at such time, for an aggregate purchase price of not more than US $13.0 million. The program was pursuant to a normal course issuer bid and conducted in accordance with Rule 10b-18 under the Exchange Act. The program commenced on February 12, 2025 and expired on February 11, 2026. No shares were repurchased under this program.

On November 14, 2025, after receiving shareholder approval following a special meeting, the Company closed on the acquisition of Peak Exploration and Production LLC and Peak BLM Lease LLC and their subsidiaries (together, "Peak"). As consideration, 7,916,336 common shares were issued to the shareholders of Peak after the satisfaction of the conditions of the contingent share consideration and all closing purchase price adjustments.

On December 31, 2025, our Board made grants to our management, employees, and directors entitling them to receive an aggregate of 488,283 common shares which shall not be issued to the award recipients unless certain time based vesting criteria are met, in which case the vesting will occur in three equal parts on the succeeding periods ending on December 31. Additionally, 47,417 common shares were issued as dividend equivalent rights. The awards were made under the 2020 Equity Incentive plan in accordance with Rule 701 promulgated under the Securities Act.

The Company funds the purchases of its shares out of available cash and does not incur debt to fund the share repurchase program. The shares are accounted for as treasury shares until such a time as they are retired. There were no common share purchases made by the Company during the three months ended December 31, 2025.

ITEM 6. [RESERVED.]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion is intended to assist in the understanding of trends and significant changes in our results of operations and the financial condition of Epsilon Energy Ltd. and its subsidiaries for the periods presented. This section should be read in conjunction with the audited consolidated financial statements as of December 31, 2025 and 2024 and for the years then ended together with accompanying notes.

Overview

Epsilon Energy Ltd. (the "Company") is a North American onshore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves. Our areas of operations are the Appalachian Basin in Pennsylvania, the Powder River Basin in Wyoming, the Permian Basin in Texas and New Mexico, and the Western Canadian Sedimentary Basin in Alberta, Canada.

At December 31, 2025 our total estimated net proved reserves were 86.4 Bcf of natural gas reserves, 9.3 MMBbls of oil reserves, and 2.4 MMBbls of NGL reserves, and we held leasehold rights to approximately 101,265 gross (54,044 net) acres. We have natural gas production from our non-operated wells in Pennsylvania and natural gas, natural gas liquids, and oil production from our operated and non-operated wells in the Permian, Powder River, and Western Canadian Sedimentary Basins.

We are committed to disciplined capital allocation which could include shareholder returns in the form of dividends and/or share buybacks. We plan to maintain a strong balance sheet and liquidity position to allow us to opportunistically invest in both our existing project areas and potential new projects.

Our Pennsylvania ("PA") assets are supported by our 35% ownership in the Auburn GGS.

We have a substantial remaining drillable location inventory within our existing leaseholds in Pennsylvania, Wyoming, and Texas.

On November 14, 2025, Epsilon acquired Peak Exploration and Production LLC and Peak BLM Lease LLC and their subsidiaries (together, "Peak") through a business combination. The acquisition added 284 gross (60 net) wells, including 105 gross (45 net) operated wells, and 60,945 gross (39,566 net) acres located in Campbell, Converse and Johnson Counties, Wyoming.

On December 11, 2025, Epsilon divested Dewey Energy Holdings, LLC, a wholly owned subsidiary of the Company to an undisclosed private buyer. The assets sold included approximately 964 Mcfe/d (60% natural gas) of production and approximately 6,400 net deep acres and 2,200 net shallow acres of leasehold, all located in Dewey County, Oklahoma.

During 2025, we realized net loss of $5.8 million as compared to net income of $1.9 million for 2024. This included a $19.3 million loss in Q4 2025 on the sale of our Anadarko Basin assets in Oklahoma, which provides potential tax benefits that may be utilized going forward.

At December 31, 2025, our total estimated net proved developed reserves were 109,444 MMcfe, a 69% increase from December 31, 2024. The increase is mainly attributable to Wyoming reserves acquired from the Peak acquisition.

At December 31, 2025, our total estimated net proved reserves were 156,037 MMcfe, a 86% increase from December 31, 2024. The increase is mainly attributable to Wyoming reserves acquired from the Peak acquisition.

Our standardized measure of discounted future net cash flows as of December 31, 2025 and 2024 was $156.1 million and $50.7 million, respectively. This measure of discounted future net cash flows does not include any estimate for future cash flows generated by our gathering system assets.

Results of Operations

The following review of operations for the periods presented below should be read in conjunction with our consolidated financial statements and the notes thereto.

Revenues

During the year ended December 31, 2025, revenues increased $20.1 million, or 64%, to $51.6 million from $31.5 million during the year ended December 31, 2024.

Revenue and volume statistics for the years ended December 31, 2025 and 2024 were as follows:

	Year ended December 31, 2025	Year ended December 31, 2024
Revenues		
Pennsylvania		
Natural gas revenue	$ 28,012,040	$ 10,247,834
Volume (MMcf)	9,402	5,699
Avg. Price ($/Mcf)	$ 2.98	$ 1.80
Gathering system revenue (net of elimination)	$ 6,683,735	$ 5,524,063
Total PA Revenues	**$ 34,695,775**	**$ 15,771,897**
Permian Basin		
Natural gas revenue	$ 113,038	$ 32,930
Volume (MMcf)	161	205
Avg. Price ($/Mcf)	$ 0.70	$ 0.16
Natural gas liquids revenue	$ 706,010	$ 1,060,967
Volume (MBoe)	36.2	51.8
Avg. Price ($/Bbl)	$ 19.51	$ 20.48
Oil and condensate revenue	$ 9,614,603	$ 12,770,258
Volume (MBbl)	149.1	173.0
Avg. Price ($/Bbl)	$ 64.50	$ 73.81
Total Permian Basin Revenues	**$ 10,433,651**	**$ 13,864,155**
Oklahoma		
Natural gas revenue	$ 640,607	$ 505,304
Volume (MMcf)	197	237
Avg. Price ($/Mcf)	$ 3.25	$ 2.13
Natural gas liquids revenue	$ 318,108	$ 420,991
Volume (MBoe)	14.1	17.4
Avg. Price ($/Bbl)	$ 22.56	$ 24.16
Oil and condensate revenue	$ 507,406	$ 844,265
Volume (MBbl)	9.4	11.0
Avg. Price ($/Bbl)	$ 54.11	$ 76.75
Total OK Revenues	**$ 1,466,121**	**$ 1,770,560**
Wyoming		
Natural gas revenue	$ 291,933	$ —
Volume (MMcf)	189	—
Avg. Price ($/Mcf)	$ 1.54	$ —
Natural gas liquids revenue	$ 872,263	$ —
Volume (MBoe)	27	—
Avg. Price ($/Bbl)	$ 32.48	$ —
Oil and condensate revenue	$ 2,840,537	$ —
Volume (MBbl)	50.1	—
Avg. Price ($/Bbl)	$ 56.66	$ —
Total WY Revenues	**$ 4,004,733**	**$ —**
Canada		
Natural gas revenue	$ 63,828	$ —
Volume (MMcf)	52	—
Avg. Price ($/Mcf)	$ 1.22	$ —
Natural gas liquids revenue	$ 82,479	$ —
Volume (MBoe)	3.6	—
Avg. Price ($/Bbl)	$ 23.01	$ —
Oil and condensate revenue	$ 840,969	$ 116,163
Volume (MBbl)	15.1	2.5
Avg. Price ($/Bbl)	$ 55.84	$ 46.04
Total Canada Revenues	**$ 987,276**	**$ 116,163**
Total Revenues	**$ 51,587,556**	**$ 31,522,775**

Upstream natural gas revenue for the year ended December 31, 2025 increased by $18.3 million, or 170%, from 2024. An increase of $11.6 million was due to higher natural gas prices and an increase of $6.8 million was due to higher produced volumes as a result of previously delayed wells coming on line and the end of operator-elected well shut-ins in Pennsylvania.

Upstream natural gas liquids revenue for the year ended December 31, 2025 increased by $0.5 million, or 34% from 2024. An increase of $0.2 million was due to higher produced volumes from new wells in the Permian and Powder River Basins and an increase of $0.3 million was due to higher natural gas liquids prices.

Upstream oil and condensate revenue for the year ended December 31, 2025 increased by $0.1 million, or 1% over 2024. An increase of $2.7 million was due to increased production from new wells in the Permian and Powder River Basins offset by a reduction of $2.6 million due to lower oil prices.

Gathering system revenue (net of elimination) for the year ended December 31, 2025 increased by $1.2 million, or 21% over 2024. The increase was primarily due to slightly higher throughput, but more importantly, crossflow gas being displaced with Anchor Shipper gas which is charged a higher gathering fee. Revenues derived from transporting and compressing our production, which have been eliminated from gathering system revenues, amounted to $1.9 million and $1.1 million, respectively, for the years ended December 31, 2025 and 2024.

Operating Costs

The following table presents total cost and cost per unit of production (Mcfe), including ad valorem, severance, and production taxes for the years ended December 31, 2025 and 2024:

	Year ended December 31,	
	2025	**2024**
Lease operating costs (net of elimination)	$ 12,518,325	$ 7,264,824
Gathering system operating costs	2,362,036	2,265,190
	$ 14,880,361	**$ 9,530,014**
Upstream operating costs—Total $/Mcfe	$ 1.06	$ 0.95
Gathering system operating costs $/Mcf	$ 0.16	$ 0.17

Operating costs include the effects of elimination entries to remove the gathering fees paid to Epsilon's ownership in the gathering system.

Upstream operating costs consist of lease operating expenses necessary to extract natural gas and oil, including gathering and treating the natural gas and oil to prepare it for sale. For the year ended December 31, 2025, upstream operating costs increased by $5.3 million, or 72% from the same period in 2024. The increase is primarily due to the increase in gas production in Pennsylvania and the acquired production in the Powder River Basin. The higher unit operating cost is primarily due to the higher liquids (oil and natural gas liquids) proportion of total sales (Mcfe).

Gathering system operating costs consist primarily of rental payments for the natural gas fueled compression units and overhead fees due to the system's operator. For the year ended December 31, 2025, gathering system operating costs decreased by $0.1 million, or 4% from the same period in 2024.

Depletion, Depreciation, Amortization and Accretion (DD&A)

	Year ended December 31,	
	2025	**2024**
Depletion, depreciation, amortization and accretion	**$ 12,170,320**	**$ 10,185,119**

Natural gas and oil and gathering system assets are depleted and depreciated using the units of production method aggregating properties on a field basis. For leasehold acquisition costs and the cost to acquire proved and unproved properties, the reserve base used to calculate depreciation and depletion is total proved reserves. For natural gas and oil development and gathering system costs, the reserve base used to calculate depletion and depreciation is proved developed reserves. A reserve report is prepared as of December 31, each year.

Depreciation expense includes amounts pertaining to our office furniture and fixtures, leasehold improvements and computer hardware. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets, ranging from 3 to 7 years. Also included in depreciation expense is an amount pertaining to buildings owned by the Company. Depreciation for the buildings is calculated using the straight-line method over an estimated useful life of 30 years.

Accretion expense is related to the asset retirement costs.

During the year ended December 31, 2025, DD&A expense increased by $2 million, or 19%, compared to the same period in 2024. This increase was primarily a result of higher produced volumes in Pennsylvania and acquired properties in Wyoming.

Impairment

	Year ended December 31,	
	2025	2024
Impairment	**$ 3,936,669**	**$ 1,450,076**

We perform a quantitative impairment test whenever events or changes in circumstances indicate that an asset group's carrying amount may not be recoverable, over proved properties using the market forward prices, timing, methods and other assumptions consistent with historical periods. When indicators of impairment are present, GAAP requires that the Company first compare expected future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount of the natural gas properties to their estimated fair values is required. Additionally, GAAP requires that if an exploratory well is determined not to have found proved reserves, the costs incurred, net of any salvage value, should be charged to expense.

For the year ended December 31, 2025, the Company recorded an impairment of $3.2 million on the Canadian wells (2 gross, 0.5 net) and $0.7 million on the New Mexico wells (2 gross, 0.2 net) due to low forward oil prices on December 31, 2025 (which are required to be used in impairment testing) and an offset frac hit impacting production and reserves in New Mexico. During the year ended December 31, 2024, Epsilon recorded an impairment of $1.45 million on the Killam project (interest acquired in April 2024) in Alberta, Canada as a result of a decrease in forecasted reserves.

Loss on Sale of Assets

	Year ended December 31,	
	2025	2024
Loss on sale of assets	**$ 19,256,530**	**$ —**

For the year ended December 31, 2025, the Company sold all of its interests in Oklahoma for $2.5 million. This resulted in a loss on the sale of $19.3 million, primarily on undeveloped leasehold. The Company had no asset sales in 2024.

Transaction Costs

	Year ended December 31,	
	2025	2024
Transaction Costs	**$ 2,947,907**	**$ —**

For the year ended December 31,2025, the Company had transaction costs related to the Peak acquisition of $2.9 million for advisory and legal services incurred by the Company.

General and Administrative ("G&A")

	Year ended December 31, 2025	2024
General and administrative expenses		
Stock based compensation expense	**$ 1,744,917**	**$ 1,244,416**
Other general and administrative expense	**7,168,235**	**5,688,714**
Total general and administrative expenses	**$ 8,913,152**	**$ 6,933,130**

G&A expenses consist of general corporate expenses such as compensation, legal, accounting and professional fees, consulting services, travel and other related corporate costs such as restricted shares of stock granted and the related non-cash compensation.

G&A expenses for the year ended December 31, 2025 increased by $2 million, or 29%, compared to the same period in 2024. An increase of $1.2 million is related to higher compensation expense, an increase of $0.5 million in stock based compensation, and an increase of $0.1 million in audit and tax fees.

Interest Income

	Year ended December 31, 2025	2024
Interest income	**$ 188,369**	**$ 493,277**

During the year ended December 31, 2025, interest income decreased by $0.3 million, or 62%, from the same period in 2024. This decrease was primarily due to the reduction in the balance of cash equivalents associated with the maturation of all short term investments in June 2024.

Interest Expense

	Year ended December 31, 2025	2024
Interest expense	**$ 624,160**	**$ 46,400**

Interest expense relates to the interest and commitment fees paid on the revolving line of credit.

Interest expense increased by $0.6 million, or 1245%, during the year ended December 31, 2025 from 2024. The increase is due to interest charged on the outstanding debt balance from the closing of the Peak acquisition on November 14, 2025, commitment fees on unused debt capacity, and the amortization of front-end fees related to the new credit facility entered into in October 2025.

Gain (Loss) on Derivative Contracts, net

	Year ended December 31, 2025	2024
Gain (loss) on derivative contracts, net	**$ 5,500,486**	**$ (391,147)**

During the year ended December 31, 2025, the Company had NYMEX Henry Hub ("HH") Natural Gas Futures swaps, NYMEX HH options, and crude oil NYMEX WTI CMA swaps derivative contracts for the purpose of hedging a portion of its physical natural gas and oil sales revenue. During the year ended December 31, 2024, the Company had NYMEX HH Natural Gas Futures swaps, Tennessee Gas Pipeline Zone 4 basis swaps, and crude oil NYMEX HH CMA swaps derivative contracts for the same hedging purpose. The amounts recorded represent the fair value changes on our derivative instruments during the year. For the year ended December 31, 2025, the Company received net cash settlements of $1,163,662. For the year ended December 31, 2024, the Company received net cash settlements of $1,196,656.

At December 31, 2025, the Company had outstanding NYMEX HH swaps totaling 1.68 Bcf, NYMEX HH options totaling 4.51 Bcf, NYMEX WTI CMA swaps totaling 340,916 Bbls, and NYMEX WTI CMA options totaling 181,634 Bbls for the contract period of January 2026 to January 2028.

At December 31, 2024, the Company had outstanding NYMEX HH swaps totaling 2.2615 Bcf and Tennessee Z4 basis swaps totaling 2.2615 Bcf for the contract period of January 2025 to October 2025, and NYMEX WTI CMA swaps totaling 20,662 Bbls for the contract period of January 2025 to June 2025.

Income Tax (Benefit) Expense

	Year ended December 31,	
	2025	2024
Income tax expense	**$ 362,731**	**$ 1,629,093**

During the year ended December 31, 2025, income tax expense decreased by $1.3 million, or 78%, from the same period in 2024. This decrease was primarily due to a decrease in taxable income as a result of loss on the asset sale, as well as increased expenses related to the Peak acquisition.

Net (Loss) Income Compared to Adjusted EBITDA

	Year ended December 31,	
	2025	**2024**
Net (loss) income	$ (5,798,863)	$ 1,927,800
Add Back:		
Interest expense (income), net	435,791	(446,877)
Income tax (benefit) expense	362,731	1,629,093
Depreciation, depletion, amortization, and accretion	12,170,320	10,185,119
Impairment expense	3,936,669	1,450,076
Stock based compensation expense	1,744,917	1,244,416
Loss on sale of assets	19,256,530	—
Transaction costs	2,947,907	
(Gain) loss on derivative contracts net of cash received or paid on settlement	(4,336,824)	1,587,803
Foreign currency translation loss	24,805	570
Adjusted EBITDA	**$ 30,743,983**	**$ 17,578,000**

We define Adjusted EBITDA as earnings before (1) net interest expense, (2) taxes, (3) depreciation, depletion, amortization and accretion expense, (4) impairments of natural gas and oil properties, (5) non-cash stock compensation expense, (6) gain or loss on sale of assets, (7) gain or loss on derivative contracts net of cash received or paid on settlement, (8) transaction costs and (9) gain or loss on foreign currency translation. Adjusted EBITDA is not a measure of financial performance as determined under U.S. GAAP and should not be considered in isolation from or as a substitute for net income or cash flow measures prepared in accordance with U.S. GAAP or as a measure of profitability or liquidity.

Additionally, Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. We have included Adjusted EBITDA as a supplemental disclosure because its management believes that Adjusted EBITDA provides useful information regarding our ability to service debt and to fund capital expenditures. It further provides investors a helpful measure for comparing operating performance on a "normalized" or recurring basis with the performance of other companies, without giving effect to certain non-cash expenses and other items. This provides management, investors and analysts with comparative information for evaluating us in relation to other natural gas and oil companies providing corresponding non-U.S. GAAP financial measures or that have different financing and capital structures or tax rates. These non-U.S. GAAP financial measures should be considered in addition to, but not as a substitute for, measures for financial performance prepared in accordance with U.S. GAAP. The table above sets forth a reconciliation of net income to Adjusted EBITDA, which is the most directly comparable measure of financial performance calculated under U.S. GAAP and should be reviewed carefully.

Capital Resources and Liquidity

Cash Flow

The primary source of cash during the year ended December 31, 2025 was funds generated from operations and financing activities. The primary source of cash during the year ended December 31, 2024 was funds generated from operations and proceeds from short term investments. For the year ended December 31, 2025 the primary uses of cash were development of upstream properties, the distribution of dividends, and costs related to the Peak acquisition. For the year ended December 31, 2024 the primary uses of cash were the acquisition and development of upstream properties and the distribution of dividends.

At December 31, 2025, we had a working capital surplus of $7.6 million, an increase of $0.5 million from the $7.1 million surplus at December 31, 2024. The surplus increased from December 31, 2024 due to an increase in current assets. We anticipate that our current cash balance, available borrowings, and cash flows from operations to be sufficient to meet our cash requirements for at least the next twelve months.

Year ended December 31, 2025 compared to 2024

During the year ended December 31, 2025, $20.6 million was provided by our operating activities, compared to $16.8 million in 2024, a $3.8 million, or 23%, increase. The increase was primarily due to higher production and throughput volumes in Pennsylvania due to new wells turned on line as well as curtailed wells returning to production.

The Company used $61.6 million for investing activities during the year ended December 31, 2025, compared to $16.7 million in 2024, a $44.9 million, or 270%, increase. The increase was primarily due to $49.8 million paid for the Peak acquisition.

During the year ended December 31, 2025, $43.7 million was provided by financing activities compared to $7.3 million used in 2024, a $51 million, or 697% decrease. The decrease was primarily due to the $50.5 million draw on the Company's credit facility to repay the outstanding debt of Peak related to the acquisition.

Credit Agreement

The Company closed a new senior secured reserve based revolving credit facility on October 10, 2025 with Frost Bank as administrative agent and Frost Bank and Texas Capital Bank as lenders. This replaced the Company's previous credit facility. As of December 31, 2025, the borrowing base was $80 million, supported by the Company's producing reserves and is subject to semi-annual redeterminations with a maturity date of October 10, 2029. Interest will be charged at the 3-month Term SOFR rate plus a margin of 3-4% (depending on facility utilization), payable quarterly. The facility is secured by the assets of the Company's Epsilon Energy USA subsidiary. During March 2026, the Company made a $5 million repayment on the outstanding credit facility. The current balance as of March 25, 2026 is $45.5 million.

Under the terms of the facility, the Company must adhere to the following financial covenants:

- Current ratio of 1.0 to 1.0 (current assets / current liabilities)
- Leverage ratio of less than 2.5 to 1.0 (total debt / income adjusted for interest, taxes and non-cash amounts)

Additionally, the Company is required to hedge 50% of its forecasted Proved Developed Producing production over a rolling 18-month period. If the facility utilization drops below 50%, then the required hedging drops to 25% of Proved Developed Producing production for the last 6 months of the 18-month period.

Repurchase Transactions

On February 18, 2026, the Board authorized a new share repurchase program of up to 3,014,986 common shares, representing 10% of the current outstanding common shares of Epsilon, for an aggregate purchase price of not more than

US $15.0 million. The program is pursuant to a normal course issuer bid and will be conducted in accordance with Rule 10b-18 under the Exchange Act. The program will commence on February 19, 2026 and end on February 18, 2027, unless the maximum amount of common shares is purchased before then or the Board approves earlier termination.

On February 12, 2025, the Board authorized a new share repurchase program of up to 2,200,876 common shares, representing 10% of the outstanding common shares of the Company at such time, for an aggregate purchase price of not more than US $13.0 million. The program is pursuant to a normal course issuer bid and conducted in accordance with Rule 10b-18 under the Exchange Act. The program commenced on February 12, 2025 and expired on February 11, 2026. No shares were repurchased under this program.

On March 19, 2024, the Board of Directors authorized a new share repurchase program of up to 2,191,320 common shares, representing 10% of the outstanding common shares of Epsilon at such time, for an aggregate purchase price of not more than US $12.0 million. The program was pursuant to a normal course issuer bid and was conducted in accordance with Rule 10b-18 under the Exchange Act. The program commenced on March 27, 2024 and expired on February 12, 2025, when the Board terminated and revoked authority under the program. During the year ended December 31, 2024, we repurchased 125,000 common shares and spent $627,500 at an average price of $5.00 per share (excluding commissions) under the plan.

In 2024, the Company also repurchased 248,700 common shares and spent $1,203,708 at an average price of $4.82 per share (excluding commissions) and retired 319,574 common shares under the 2023-2024 repurchase program before the plan terminated on March 26, 2024. During the year ended December 31, 2024, the Company repurchased a total of 373,700 shares and spent $1,831,208 at an average price of $4.88 per share (excluding commissions) under the two previous repurchase programs.

Derivative Transactions

The Company has entered into hedging arrangements to reduce the impact of natural gas and oil price volatility on operations. By removing the price volatility from a significant portion of natural gas and oil production, the potential effects of changing prices on operating cash flows have been mitigated, but not eliminated. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we might otherwise receive from increases in commodity prices.

At December 31, 2025, Epsilon's outstanding natural gas and crude oil commodity contracts consisted of the following:

		Weighted Average Price ($/Mmbtu)			
Derivative Type	**Volume (MMbtu)**	**Swaps**	**Ceiling Price**	**Floor Price**	**Fair Value of Asset December 31, 2025**
2026					
NYMEX Henry Hub (LD) Options Call	2,360,801	$ —	$ 5.05	$ —	$ (295,384)
NYMEX Henry Hub (LD) Options Put	—	$ —	$ —	$ 3.35	$ 709,792
NYMEX Henry Hub (LD) Swaps	1,339,777	$ 4.00	$ —	$ —	$ 632,140
2027					
NYMEX Henry Hub (LD) Options Call	2,126,016	$ —	$ 4.87	$ —	$ (631,696)
NYMEX Henry Hub (LD) Options Put	—	$ —	$ —	$ 3.29	$ 639,282
NYMEX Henry Hub (LD) Swaps	312,297	$ 3.76	$ —	$ —	$ (32,489)
2028					
NYMEX Henry Hub (LD) Options Call	27,978	$ —	$ 4.70	$ —	$ (22,920)
NYMEX Henry Hub (LD) Options Put	—	$ —	$ —	$ 3.65	$ 8,513
NYMEX Henry Hub (LD) Swaps	27,978	$ 4.46	$ —	$ —	$ (7,910)
	6,194,847				$ 999,328

Derivative Type	Volume (Bbl)	Weighted Average Price ($/Mmbtu) Swaps	Ceiling Price	Floor Price	Fair Value of Asset December 31, 2025
2026					
NYMEX WTI CMA Options Call	55,230	$ —	$ 69.23	$ —	$ (63,877)
NYMEX WTI CMA Options Put	—	$ —	$ —	$ 59.37	$ 313,499
NYMEX WTI CMA Swaps	226,622	$ 63.21	$ —	$ —	$ 1,398,170
2027					
NYMEX WTI CMA Options Call	118,096	$ —	$ 67.82	$ —	$ (384,927)
NYMEX WTI CMA Options Put	—	$ —	$ —	$ 57.60	$ 839,353
NYMEX WTI CMA Swaps	105,986	$ 63.76	$ —	$ —	$ 679,105
2028					
NYMEX WTI CMA Options Call	8,308	$ —	$ 67.96	$ —	$ (33,685)
NYMEX WTI CMA Options Put	—	$ —	$ —	$ 57.57	$ 61,503
NYMEX WTI CMA Swaps	8,308	$ 62.97	$ —	$ —	$ 40,807
	522,550				$ 2,849,948

Contractual Obligations

The following table summarizes our contractual obligations at December 31, 2025.

	Payments Due by Period Total	Less than 1 Year	1 – 3 Years	Greater than 3 Years
Derivative liabilities	$ 1,552,027	$ 410,342	$ 1,141,685	$ —
Asset retirement obligations, undiscounted	18,765,954	—	—	18,765,954
Capital expenditure commitments	3,828,678	3,828,678	—	—
Total future commitments	$ 24,146,659	$ 4,239,020	$ 1,141,685	$ 18,765,954

We enter into commitments for capital expenditures in advance of the expenditures being made. As of December 31, 2025, our commitments for capital expenditures were $3.8 million related to the drilling of 1 gross (0.25 net) well in Texas.

Summary of Critical Accounting Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements and accompanying notes, which have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP, and SEC rules which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition, results of operations or liquidity, and the degree of difficulty, subjectivity and complexity in their application. Critical accounting estimates cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting estimates. Described below are the most significant accounting policies we apply in preparing our consolidated financial statements. We also describe the most significant estimates and assumptions we make in applying these policies.

Proved Natural Gas and Oil Reserves

Our engineers estimate proved natural gas and oil reserves in accordance with SEC regulations, which directly impact financial accounting estimates, including depreciation, depletion and amortization and impairments of proved properties and related assets. Proved reserves represent estimated quantities of crude oil and condensate, NGLs and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating future production volumes of proved natural gas and oil reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. There are uncertainties inherent in the interpretation of such data, as well as the projection of future rates of production and timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. Accordingly, there can be no assurance that ultimately, the reserves will be produced, nor can there be assurance that the proved undeveloped reserves will be developed within the period anticipated. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. We cannot predict the types of reserve revisions that will be required in future periods. For related discussion, see the sections titled "Risk Factors" and "Supplemental Information to Consolidated Financial Statements."

Impairments

The carrying value of unproved and proved oil and natural gas properties and gathering system assets are reviewed for impairment whenever events indicate that the carrying amounts for those assets may not be recoverable. Such indicators include changes in our business plans, changes in commodity prices leading to unprofitable performance, and, for natural gas and oil properties, significant downward revisions of estimated proved reserve quantities or significant increases in the estimated development costs.

We compare expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the carrying value of the asset. If the expected undiscounted future cash flows, based on our estimates of (and assumptions regarding) future oil and natural gas prices, operating costs, development expenditures, anticipated production from proved reserves and other relevant data, are lower than the carrying value of the asset, the carrying value is reduced to fair value. Fair value is generally calculated using the "Income Approach" based on estimated discounted net cash flows. Estimates of future cash flows require significant judgment, and the assumptions used in preparing such estimates are inherently uncertain. In addition, such assumptions and estimates are reasonably likely to change in the future. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices and (iv) a market-based weighted average cost of capital rate.

We evaluate impairment of proved natural gas and oil properties on an area basis. On this basis, certain fields may be impaired because they are not expected to recover their entire carrying value from future net cash flows. The basis for future depletion, depreciation, amortization, and accretion will take into account the reduction in the value of the asset as a result of any accumulated impairment losses. Unproved natural gas and oil properties are assessed periodically for impairment based on remaining lease terms, drilling results, reservoir performance, future plans to develop acreage, and other relevant factors.

When circumstances indicate that the gathering system properties may be impaired, Epsilon compares expected undiscounted future cash flows related to the gathering system to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach, which considers estimated discounted future cash flows.

Asset Retirement Obligations ("ARO")

We recognize asset retirement obligations under ASC 410, Asset Retirement and Environmental Obligations. ASC 410 requires legal obligations associated with the retirement of long-lived assets to be recognized at their fair value at the time that the obligations are incurred. For our upstream properties, these obligations consist of estimated future costs associated with the plugging and abandonment of natural gas and oil wells, removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. For our gathering system, these obligations consist of estimated future costs associated with the removal of equipment and facilities from leased acreage and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the natural gas and oil or gathering system asset. The initial recognition of an ARO fair value requires that management make numerous assumptions regarding such factors as the amounts and timing of settlements; the credit-adjusted risk-free discount rate; and the inflation rate. In periods subsequent to the initial measurement of an ARO, period-to-period changes are recognized in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the natural gas and oil property or gathering system asset.

Income Taxes

Tax regulations and legislation in the U.S. and Canada are subject to change and differing interpretations requiring judgment. We compute income taxes using the asset-and-liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amounts of existing assets and liabilities, as well as loss and tax credit carryforwards. Changes in tax rates and laws are recognized in income in the period such changes are enacted.

We establish a valuation allowance if, based on available evidence, it is more likely than not that some or all of the deferred tax assets will not be realized. We consider all positive and negative evidence, including historical operating results, the existence of cumulative losses, estimates of future operating income, and the reversal of existing taxable temporary differences in assessing the need for a valuation allowance. Income tax filings are subject to audits and re-assessments. Changes in facts, circumstances, and interpretations of the standards may result in a material increase or decrease in our provision for income taxes.

Business Combinations

We account for acquisitions that have been determined to be business combinations using the acquisition method of accounting. Accordingly, identifiable assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values.

We made a number of assumptions in estimating the fair value of assets acquired and liabilities assumed in these acquisitions. The most significant assumptions relate to the estimated fair values of proved and unproved oil and gas properties. The fair value of identifiable assets acquired and liabilities assumed is determined based on various valuation techniques, including market prices, discounted cash flow analysis, and independent appraisals. Significant judgments and assumptions are inherent in these valuation techniques and include, among other things, estimates of reserves, estimates of future production volumes, estimates of future commodity prices, expected development costs, lease operating costs and the discount rate that reflects the risk of the underlying cash flow estimates.

Estimated fair values assigned to assets acquired can have a significant impact on future results of operations presented in the Company's financial statements. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net income. In the event that future commodity prices or reserve quantities are lower than those used as inputs to determine estimates of acquisition date fair values, the likelihood increases that certain costs may be determined to not be recoverable.

Recently Issued Accounting Standards

See Note 3, "Summary of Significant Accounting Policies" in Notes to the Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Our earnings and cash flow are significantly affected by changes in the market price of commodities. The prices of oil and natural gas can fluctuate widely and are influenced by numerous factors such as demand, production levels, and world political and economic events and the strength of the U.S. dollar relative to other currencies. Should the price of oil or natural gas decline substantially, the value of our assets could fall dramatically, impacting our future options and exploration and development activities, along with our gas gathering system revenues. In addition, our operations are exposed to market risks in the ordinary course of our business, including interest rate and certain exposure as well as risks relating to changes in the general economic conditions in the United States.

Gathering System Revenue Risk

The Auburn GGS gather gas produced from the Marcellus Shale with historically high levels of recoverable reserves and low cost of production. We believe that a short term low commodity price environment will not significantly impact the reserves produced and thus the revenue of our gas gathering system.

Derivative Contracts

The Company's financial results and condition depend on the prices received for natural gas and oil production. Natural gas and oil prices have fluctuated widely and are determined by economic and political factors. Supply and demand factors, including weather, general economic conditions, the ability to transport the gas to other regions, as well as conditions in other natural gas and oil regions, impact prices. Epsilon has established a hedging strategy and may manage the risk associated with changes in commodity prices by entering into various derivative financial instrument agreements and physical contracts. Although these commodity price risk management activities could expose the Company to losses or gains, entering into these contracts helps to stabilize cash flows and support the Company's capital spending program.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Our consolidated balance sheets as of December 31, 2025 and 2024, and the consolidated statements of operations and comprehensive income, changes in shareholders' equity and cash flows for years ended December 31, 2025 and 2024 included in this annual report have been prepared in accordance with U.S. GAAP.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Epsilon Energy Ltd.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Epsilon Energy Ltd. (the "Company") as of December 31, 2025 and 2024, the related consolidated statements of operations and comprehensive income, changes in shareholders' equity, and cash flows for each of the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2025 and 2024, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Estimation of Future Production Volumes Used to Estimate Proved Oil and Natural Gas Reserves and the Associated Effect on Depreciation, Depletion and Amortization ("DD&A") Expense Related to Proved Oil and Natural Gas Properties

As described in Note 3 to the consolidated financial statements, the Company uses the successful efforts method of accounting for its oil and natural gas producing activities which involves management making significant estimates, including estimating the future production volumes of proved oil and natural gas reserves. As disclosed in Note 5, the Company's oil and natural gas properties, net balance as of December 31, 2025 was $181 million, which includes proved oil and natural gas properties of $233.3 million and accumulated depletion, amortization and impairment of $131.6 million. Depletion, depreciation, amortization, and accretion expense was $12.2 million for the year ended December 31, 2025.

We have identified the estimation of future production volumes used to estimate proved oil and natural gas reserves and the associated effect on DD&A expense related to proved oil and natural gas properties as a critical audit matter. Estimating future production volumes involves a high degree of subjectivity from management and their independent petroleum engineers. Changes in this estimate could have a significant effect on the measurement of DD&A expense. Auditing the estimation of future production volumes required subjective and complex auditor judgment.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the professional qualifications and objectivity of the independent petroleum engineers, including their relationship to the Company.

- Assessing the reasonableness of the future production volumes by comparing estimates of future production volumes against historical results of production volumes on a summary basis for all wells.

- Performing a retrospective review over management estimates of future production volumes made in prior periods as compared to actual results.

Estimation of Future Production Volumes Used to Estimate Fair Value of the Acquired Proved Oil and Gas Properties in the Peak Acquisition

As described in Note 4 to the consolidated financial statements, on November 14, 2025, the Company completed an acquisition of Peak E&P, LLC and Peak BLM, LLC ("Peak Acquisition") for a total consideration of $88.5 million. In connection with the Peak Acquisition, the Company recognized proved oil and gas properties of $47.9 million. To determine the acquisition date fair value of the oil and gas properties, management used internal engineers to make significant estimates, including estimating the future production volumes of the acquired oil and gas reserves.

We have identified the estimation of future production volumes used to estimate the fair value of the acquired proved oil and gas properties in the Peak Acquisition as a critical audit matter. Estimating future production volumes involves a high degree of subjectivity from management and their internal petroleum engineers. Changes in this estimate could have a significant effect on the fair value of the acquired oil and natural gas properties. Auditing the estimation of future production volumes requires subjective and complex auditor judgement.

The primary procedures we performed to address this critical audit matter included:

- Assessing the reasonableness of the future production volumes by comparing estimates of future production volumes against historical results of production volumes on a summary basis for all wells and on a detailed basis for certain wells.

- Performing a retrospective review over management estimates of future production volumes made in the acquisition date fair value forecast as compared to actual results.

/s/ BDO USA, P.C.

We have served as the Company's auditor since 2017.

Houston, Texas
March 27, 2026

EPSILON ENERGY LTD.

Consolidated Balance Sheets

	December 31, 2025	December 31, 2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 8,959,954	$ 6,519,793
Accounts receivable	16,132,501	5,843,722
Fair value of derivatives	2,694,340	—
Prepaid income taxes	2,949,311	975,963
Other current assets	1,847,672	792,041
Total current assets	32,583,778	14,131,519
Non-current assets		
Property and equipment:		
Oil and gas properties, successful efforts method		
Proved properties	233,334,212	191,879,210
Unproved properties	79,307,169	28,364,186
Accumulated depletion, depreciation, amortization and impairment	(131,636,141)	(123,281,395)
Total oil and gas properties, net	181,005,240	96,962,001
Gathering system	43,540,389	43,116,371
Accumulated depletion, depreciation, amortization and impairment	(37,472,139)	(36,449,511)
Total gathering system, net	6,068,250	6,666,860
Land	1,231,965	637,764
Buildings and other property and equipment, net	4,132,732	259,335
Total property and equipment, net	192,438,187	104,525,960
Other assets:		
Operating lease right-of-use assets, long term	488,949	344,589
Restricted cash	553,000	470,000
Fair value of derivatives, long term	1,154,936	—
Deferred financing costs	774,347	—
Prepaid drilling costs	246,220	982,717
Total non-current assets	195,655,639	106,323,266
Total assets	$ 228,239,417	$ 120,454,785
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable trade	$ 11,148,050	$ 2,334,732
Gathering fees payable	1,076,143	997,016
Royalties payable	8,702,526	1,400,976
Accrued capital expenditures	24,888	572,079
Accrued compensation	1,056,304	695,018
Other accrued liabilities	2,682,090	371,503
Fair value of derivatives	—	487,548
Operating lease liabilities	271,494	121,135
Total current liabilities	24,961,495	6,980,007
Non-current liabilities		
Credit facility payable	50,500,000	—
Ad valorem taxes, long term	7,411,971	—
Asset retirement obligations	7,437,960	3,652,296
Deferred income taxes	12,855,585	12,738,577
Operating lease liabilities, long term	340,052	355,776
Total non-current liabilities	78,545,568	16,746,649
Total liabilities	103,507,063	23,726,656
Commitments and contingencies (Note 11)		
Shareholders' equity		
Preferred shares, no par value, unlimited shares authorized, none issued or outstanding	—	—
Common shares, no par value, unlimited shares authorized and 30,239,980 shares issued and outstanding at December 31, 2025 and 22,008,766 issued and outstanding at December 31, 2024	154,274,125	116,081,031
Additional paid-in capital	13,863,824	12,118,907
Accumulated deficit	(53,302,162)	(41,505,076)
Accumulated other comprehensive income	9,896,567	10,033,267
Total shareholders' equity	124,732,354	96,728,129
Total liabilities and shareholders' equity	$ 228,239,417	$ 120,454,785

The accompanying notes are an integral part of these consolidated financial statements

EPSILON ENERGY LTD.

Consolidated Statements of Operations and Comprehensive Income

	Year ended December 31, 2025	Year ended December 31, 2024
Revenues from contracts with customers:		
Gas, oil, NGL, and condensate revenue	$ 44,903,821	$ 25,998,712
Gas gathering and compression revenue	6,683,735	5,524,063
Total revenue	51,587,556	31,522,775
Operating costs and expenses:		
Lease operating expenses	12,518,325	7,264,824
Gathering system operating expenses	2,362,036	2,265,190
Depletion, depreciation, amortization, and accretion	12,170,320	10,185,119
Impairment expense	3,936,669	1,450,076
Loss on sale of oil and gas properties	19,256,530	—
Transaction costs	2,947,907	—
General and administrative expenses:		
Stock based compensation expense	1,744,917	1,244,416
Other general and administrative expenses	7,168,235	5,688,714
Total operating costs and expenses	62,104,939	28,098,339
Operating (loss) income	(10,517,383)	3,424,436
Other income (expense):		
Interest income	188,369	493,277
Interest expense	(624,160)	(46,400)
Gain (loss) on derivative contracts, net	5,500,486	(391,147)
Other income, net	16,556	76,727
Other income, net	5,081,251	132,457
Net (loss) income before income tax expense	(5,436,132)	3,556,893
Income tax (benefit) expense	362,731	1,629,093
NET (LOSS) INCOME	$ (5,798,863)	$ 1,927,800
Currency translation adjustments	(136,700)	262,588
Unrealized loss on securities	—	(1,598)
NET COMPREHENSIVE (LOSS) INCOME	$ (5,935,563)	$ 2,188,790
Net (loss) income per share, basic	$ (0.25)	$ 0.09
Net (loss) income per share, diluted	$ (0.25)	$ 0.09
Weighted average number of shares outstanding, basic	23,020,672	21,930,277
Weighted average number of shares outstanding, diluted	23,020,672	21,930,277

The accompanying notes are an integral part of these consolidated financial statements

EPSILON ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity

	Common Shares Issued		Treasury Shares		Additional	Accumulated Other	Accumulated	Total Shareholders'
	Shares	Amount	Shares	Amount	paid-in Capital	Comprehensive Income	Deficit	Equity
Balance at December 31, 2023	22,222,722	$ 118,272,565	(70,874)	$ (360,326)	$ 10,874,491	$ 9,772,277	$ (37,946,042)	$ 100,612,965
Net income	—	—	—	—	—	—	1,927,800	1,927,800
Dividends	—	—	—	—	—	—	(5,486,834)	(5,486,834)
Stock-based compensation expense	—	—	—	—	1,244,416	—	—	1,244,416
Buyback of common shares	—	—	(373,700)	(1,831,208)	—	—	—	(1,831,208)
Retirement of treasury shares	(444,574)	(2,191,534)	444,574	2,191,534	—	—	—	—
Vesting of shares of restricted stock	230,618	—	—	—	—	—	—	—
Other comprehensive income	—	—	—	—	—	260,990	—	260,990
Balance at December 31, 2024	22,008,766	$ 116,081,031	—	$ —	$ 12,118,907	$ 10,033,267	$ (41,505,076)	$ 96,728,129
Net loss	—	—	—	—	—	—	(5,798,863)	(5,798,863)
Dividends	—	—	—	—	—	—	(5,998,223)	(5,998,223)
Dividend equivalent rights	47,417	—	—	—	—	—	—	—
Stock-based compensation expense	—	—	—	—	1,744,917	—	—	1,744,917
Shares issued in business combination	7,916,336	38,193,094	—	—	—	—	—	38,193,094
Vesting of shares of restricted stock	267,461	—	—	—	—	—	—	—
Other comprehensive loss	—	—	—	—	—	(136,700)	—	(136,700)
Balance at December 31, 2025	30,239,980	$ 154,274,125	—	$ —	$ 13,863,824	$ 9,896,567	$ (53,302,162)	$ 124,732,354

The accompanying notes are an integral part of these consolidated financial statements

Consolidated Statements of Cash Flows

	Year ended December 31, 2025	Year ended December 31, 2024
Cash flows from operating activities:		
Net income	$ (5,798,863)	$ 1,927,800
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization, and accretion	12,170,320	10,185,119
Impairment expense	3,936,669	1,450,076
Accretion of discount on available for sale securities	—	(297,637)
Amortization on deferred financing costs	44,510	—
Loss on sale of oil and gas properties	19,256,530	—
(Gain) loss on derivative contracts	(5,500,486)	391,147
Settlement received on derivative contracts	1,163,662	1,196,656
Settlement of asset retirement obligation	(1,600)	(88,992)
Stock-based compensation expense	1,744,917	1,244,416
Deferred income tax (benefit) expense	117,008	1,184,634
Changes in assets and liabilities, net of assets and liabilities acquired in business combination:		
Accounts receivable	(1,588,383)	171,726
Prepaid income taxes	(1,973,348)	(23,662)
Other assets and liabilities	(10,365)	(17,828)
Accounts payable, royalties payable, gathering fees payable, and other accrued liabilities	(2,940,888)	(493,176)
Net cash provided by operating activities	20,619,683	16,830,279
Cash flows from investing activities:		
Additions to unproved oil and gas properties	(6,999,905)	(4,507,280)
Additions to proved oil and gas properties	(7,929,773)	(31,695,651)
Additions to gathering system properties	(465,203)	(341,452)
Additions to land, buildings and property and equipment	270,488	(16,513)
Purchases of short term investments - available for sale	—	(4,045,785)
Proceeds from short term investments - held to maturity	—	6,743,178
Proceeds from short term investments - available for sale	—	16,373,752
Net asset acquired in business combination	(49,754,846)	—
Proceeds from sale of oil and gas properties	2,500,000	—
Prepaid drilling costs	736,497	831,091
Net cash used in investing activities	(61,642,742)	(16,658,660)
Cash flows from financing activities:		
Buyback of common shares	—	(1,831,208)
Borrowings on credit facility	50,500,000	—
Dividends paid	(5,998,223)	(5,486,834)
Deferred financing costs	(818,857)	—
Net cash provided by (used in) financing activities	43,682,920	(7,318,042)
Effect of currency rates on cash, cash equivalents, and restricted cash	(136,700)	262,588
Increase (decrease) in cash, cash equivalents, and restricted cash	2,523,161	(6,883,835)
Cash, cash equivalents, and restricted cash, beginning of period	6,989,793	13,873,628
Cash, cash equivalents, and restricted cash, end of period	$ 9,512,954	$ 6,989,793
Supplemental cash flow disclosures:		
Income tax paid - federal	$ 1,417,860	$ 414,250
Income tax paid - state (PA)	$ 755,138	$ —
Income tax paid - state (other)	$ 3,986	$ (2,071)
Interest paid	$ 9,935	$ 16,832
Non-cash investing activities:		
Change in proved properties accrued in accounts payable	$ (937,079)	$ (862,744)
Change in gathering system accrued in accounts payable	$ (41,186)	$ 36,645
Asset retirement obligation asset additions and adjustments	$ 25,195	$ 54,902

The accompanying notes are an integral part of these consolidated financial statements

1. Description of Business

Epsilon Energy Ltd. (the "Company" or "Epsilon" or "we") was incorporated under the laws of the Province of Alberta, Canada on March 14, 2005. On February 14, 2019, Epsilon's registration statement on Form 10 was declared effective by the United States Securities and Exchange Commission and on February 19, 2019, we began trading in the United States on the NASDAQ Global Market under the trading symbol "EPSN." Epsilon is a North American on-shore focused independent natural gas and oil company engaged in the acquisition, development, gathering and production of natural gas and oil reserves.

2. Basis of Preparation

Principles of Consolidation

The Company's consolidated financial statements include the accounts of the Company and its wholly owned subsidiary, Epsilon Energy USA, Inc. and its wholly owned subsidiaries, Epsilon Midstream, LLC, Epsilon Operating, LLC, Dewey Energy GP, LLC, Peak Exploration & Production LLC, Peak BLM Lease LLC, Peak Powder River Resources, LLC, Peak Energy Operating #2, LLC, Willow Springs Development, LLC, Peak Powder River Acquisition, LLC and Altolisa Holdings, LLC. With regard to the gathering system, in which Epsilon owns an undivided interest in the asset, proportionate consolidation accounting is used. All inter-company transactions have been eliminated.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas reserves and related cash flow estimates used in impairment tests of oil and natural gas and gathering system properties, asset retirement obligations, accrued natural gas and oil revenues and operating expenses, accrued gathering system revenues and operating expenses, as well as the valuation of commodity derivative instruments. Actual results could differ from those estimates.

3. Summary of Significant Accounting Policies

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents includes cash on hand and short term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Restricted cash consists of amounts deposited to back bonds or letters of credit. The Company presents restricted cash with cash and cash equivalents in the Consolidated Statements of Cash Flows.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported in the Consolidated Balance Sheets to the total of the amounts in the Consolidated Statements of Cash Flows as of December 31, 2025 and 2024:

	December 31, 2025	December 31, 2024
Cash and cash equivalents	$ 8,959,954	$ 6,519,793
Restricted cash included in other assets	553,000	470,000
Cash, cash equivalents, and restricted cash in the statement of cash flows	$ 9,512,954	$ 6,989,793

Oil and Natural Gas Properties

Epsilon accounts for its crude oil and natural gas exploration and production activities under the successful efforts method of accounting.

Oil and natural gas lease acquisition costs are capitalized when incurred. Unproved properties with acquisition costs that are not individually significant are aggregated. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and natural gas properties. Lease delay rentals are expensed as incurred.

Oil and natural gas exploration costs, other than the costs of drilling exploratory wells, are expensed as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether Epsilon has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. In some circumstances, it may be uncertain whether proved commercial reserves have been discovered when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. Costs to develop proved reserves, including the costs of all development wells and related equipment used in the production of crude oil and natural gas, are capitalized (see Note 5).

Depreciation, depletion and amortization of the cost of proved oil and natural gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves.

When circumstances indicate that proved (developed and undeveloped) oil and natural gas properties may be impaired, Epsilon compares expected undiscounted future cash flows at a depreciation, depletion and amortization group level to the carrying value of the asset. If the expected undiscounted future cash flows, based on Epsilon's estimate of future crude oil and natural gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the carrying value of the asset, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach which considers estimated discounted future cash flows. Unproved oil and gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable.

Gas Gathering System Properties

Epsilon's 35% portion of asset development costs are capitalized when incurred. All other costs are expensed.

Depreciation, depletion and amortization of the cost of gathering system properties is calculated using the unit-of- production method. The reserve base used to calculate depreciation, depletion and amortization for the gathering system includes only proved Pennsylvania natural gas developed reserves.

When circumstances indicate that the gathering system properties may be impaired, Epsilon compares expected undiscounted future cash flows related to the gathering system to the unamortized capitalized cost of the asset. If the expected undiscounted future cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated using the Income Approach, which considers estimated discounted future cash flows.

Revenue Recognition

Revenues are comprised primarily of sales of natural gas, crude oil and NGLs, along with the revenue generated from the Company's ownership interest in the gas gathering system in the Auburn field in Pennsylvania.

Revenue recognition is evaluated through the following five steps: (i) identification of the contract, or contracts, with a customer; (ii) identification of the performance obligations in the contract; (iii) determination of the transaction price; (iv) allocation of the transaction price to the performance obligations in the contract; and (v) recognition of revenue when or as a performance obligation is satisfied.

Accounting Policies

Revenue is recognized when performance obligations under the terms of a contract with a customer are satisfied. The Company recognizes upstream revenue at the point in time when control has been transferred to the customer, generally at the time natural gas reaches an agreed-upon delivery point and collectability is reasonably assured. Upstream revenue is based upon a fixed price, based on market pricing, and is measured as the amount of consideration the Company expects to receive in exchange for the transferring of the natural gas and oil. The services provided by the gas gathering system take place continuously and as a practical expedient, the revenues are recognized monthly for the volumes that are processed and transported for the upstream producers during that period of time. Revenue for the services performed are based on the rates outlined in the Anchor Shipper Gas Gathering Agreement for Northern Pennsylvania (the "ASGGA") effective January 1, 2024 that governs all volumes gathered and processed by the system. The gathering rate is fixed, but is adjusted annually by the Consumer Price Index for All Urban Consumers ("CPI-U") as published by US Bureau of Labor Statistics. Typically, the Company sells its natural gas directly to customers, under agreements with payment terms less than 30 days after delivery and 60 days on the revenue generated by the gas gathering system. For operated assets in Wyoming, payment is received within 30 days after the end of a month for oil and 60 days after the end of the month for natural gas and NGLs.

Natural Gas Revenues

The Company's natural gas purchase contracts are generally structured such that Epsilon commits and dedicates for sale its proportionate share of natural gas production per day to a purchaser. Natural gas is sold at market prices. Control transfers at the delivery point specified in the contract, which typically is stated as the inlet of the third-party sales transportation pipeline. The Company recognizes revenue proportionate to its entitled share of volumes sold. Currently, the vast majority of Epsilon's natural gas production comes from the Appalachian Basin in Pennsylvania.

Epsilon uses a third-party service for its natural gas marketing. In this capacity, the third-party is responsible for carrying out marketing activities such as submission of nominations, receipt of payments, submission of invoices and negotiation of contracts. Commissions payable to the third-party broker for these services are treated as lease operating expenses in the financial statements.

For the Company's operated assets in Wyoming, revenues from the sale of natural gas and NGLs are recognized, as the product is delivered to the customers' custody transfer points and collectability is reasonably assured. The Company fulfills the performance obligations under the customer contracts through daily delivery of natural gas and NGLs to the customers' custody transfer points. Revenues are recorded on a monthly basis using the prices received under the Company's contracts. These contracts are generally derived from stated market prices which are adjusted to reflect deductions, including transportation, fractionation and processing. As a result, the revenues from the sale of natural gas and NGLs are subject to change with the increase or decrease in market prices. As a result, the sale of natural gas and NGLs, as presented on the consolidated statements of operations, represent the Company's share of revenues, net of gathering and processing costs, net of royalties and excluding revenue interests owned by others. When selling natural gas and NGLs on behalf of royalty owners or working interest owners, the Company acts as an agent and therefore reports the revenue on a net share basis. To the extent actual volumes and prices of natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Historically, differences between revenue estimates and actual revenue received have not been significant.

The majority of product sale commitments of the Company are short term in nature with a contractual term of one year or less. For these contracts, the Company applies the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14, which exempts entities from disclosing the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

For contracts with terms greater than one-year, the Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in ASC 606-10-50-14A, which applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Gas Gathering System Revenue

The Company has a 35% ownership interest in the Auburn GGS. This system aggregates the natural gas from the various pads in the field and transports the natural gas to the inlet of the Auburn CF where it is dehydrated, compressed and injected into the Tennessee Gas Pipeline. The gathering and compression services operate under fee-based contracts. The producers in the area served by the gathering system pay fees to the system owners based on the services provided to them in getting their share of the gas production to the third-party sales transmission point. Revenue is recognized over time as the services are provided.

Oil and Natural Gas Liquids Revenue

The source of the Company's oil and natural gas liquids revenue is its ownership in wells in Wyoming, the Permian Basin, and Alberta, Canada. With the exception of Wyoming, the Company does not operate the wells and has elected not to receive its proportionate share of the production. As such, under the Joint Operating Agreement, the operators have control of the marketing of this production at current market prices and remits our net revenue interest less taxes and fees on a monthly basis. The Company recognizes revenue with a monthly accrual of its proportionate share of volumes produced at an estimated market price.

For the Company's operated assets in Wyoming, revenue from the sale of oil and natural gas liquids are recognized, as the product is delivered to the customers' custody transfer points and collectability is reasonably assured. The Company fulfills the performance obligations under the customer contracts through daily delivery of oil and natural gas liquids to the customers' custody transfer points. Revenues are recorded on a monthly basis using the prices received under the Company's contracts. These contracts are generally derived from stated market prices which are adjusted to reflect deductions, including transportation, fractionation and processing. As a result, the revenues from the sale of oil and natural gas liquids are subject to change with the increase or decrease in market prices. As a result, the sales of oil and natural gas liquids, as presented on the consolidated statements of operations, represent the Company's share of revenues, net of gathering and processing costs, net of royalties and excluding revenue interests owned by others. When selling oil and natural gas liquids on behalf of royalty owners or working interest owners, the Company acts as an agent and therefore reports the revenue on a net share basis. To the extent actual volumes and prices of oil and natural gas liquids sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Historically, differences between revenue estimates and actual revenue received have not been significant.

The majority of product sale commitments of the Company are short term in nature with a contractual term of one year or less. For these contracts, the Company applies the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14, which exempts entities from disclosing the transaction price allocated to remaining performance obligations, if any, if the performance obligation is part of a contract that has an original expected duration of one year or less.

For contracts with terms greater than one-year, the Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in ASC 606-10-50-14A, which applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Accounts Receivable

Oil, natural gas liquid and natural gas receivables consist of amounts due from purchasers or operators for commodity sales from our revenue interest in the leases in Pennsylvania, Wyoming, the Permian Basin, and Alberta, Canada. Payments from purchasers are typically due by the last day of the month following the month of delivery. Gathering fee revenue consists of fees due from the operator of the Auburn GGS, as an agent for the Company fulfilling the operations of the gathering system. Payments from the operator are typically due 60 days from the last day of the month of transmission. The Company's operations do not result in any contract assets or liabilities on the accompanying consolidated balance sheets.

For its operated assets in Wyoming, the Company accrues for oil, natural gas and natural gas liquids sales based on actual production dates. These are due within 45 days of production for oil and 60 days for natural gas and other liquids. To the extent the Company has joint interest owners in properties, joint interest billings represent monthly billings to working interest owners in the properties the Company operates. Joint interest billings are due within 30 days, with a right of offset against revenues due to working interest owners in the respective properties. The Company monitors the creditworthiness of its counterparties by reviewing credit ratings, financial statements, and payment history.

Buildings and Other Property and Equipment

Buildings are depreciated on a straight-line basis over the estimated useful life of the property, 30 years. The Company's office building in Durango is stated at cost and depreciated over the estimated useful life of 25 years using straight-line method.

Other property and equipment consists of computer hardware and software, and furniture and fixtures. Other property and equipment is generally depreciated on a straight-line basis over the estimated useful lives of the property and equipment, which range from 3 years to 7 years.

Financial Instruments and Fair Value

Epsilon's financial instruments consist of cash and cash equivalents, restricted cash, commodity derivative contracts, accounts receivable, accounts payable, and long term debt.

The Company classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3—Valuations in this level are those with inputs for the asset or liability that are not based on observable market data. The Company makes its own assumptions about how market participants would price the assets and liabilities.

Cash, restricted cash, accounts receivable, and accounts payable are carried at cost, which approximates fair value because of the short term maturity of these instruments. Cash equivalents are carried at fair value. The Company's revolving line of credit has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates. The revolving line of credit is classified within Level 2 of the fair value hierarchy.

Commodity derivative instruments consist of NYMEX HH and NYMEX WTI CMA swaps and options as well as basis swap contracts for natural gas. The Company's derivative contracts are valued based on a marked to market approach. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

Derivative Instruments

The Company enters into derivative contracts to hedge price risk associated with a portion of natural gas and oil production. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions sometimes arise where actual production is less than estimated, which has, and could, result in over-hedged volumes. Natural gas production is primarily sold under market sensitive contracts which are typically priced at a differential to the NYMEX or the published natural gas index prices for the producing area due to the natural gas quality and the proximity to major consuming markets. Our derivative transactions have included the following:

- Fixed-price swaps—where a fixed price is received for production and a variable market price is paid to the contract counterparty.

- Basis swap contracts—which guarantee a specified price differential between the price at Henry Hub and our physical pricing points. If the settled price differential is greater than the swapped basis, then we receive a payment from the counterparty in the amount of the difference between the two. If the settled price differential is less than the swapped basis, then we make a payment to the counterparty for the difference between the two.

- Two-way costless collar contracts—which guarantee a specified price range for NYMEX by using the proceeds of selling a call option at a specified strike price (the "Ceiling") to finance the purchase of a put option at a specified strike price (the "Floor").

Derivative instruments are recorded on the consolidated balance sheets at fair value as either current or non-current assets or liabilities based on their anticipated settlement date. Gains or losses on derivative contracts are recorded as gain (loss) on derivative contracts in the consolidated statements of operations and comprehensive income. Hedge accounting is not used for our derivative assets and liabilities.

Asset Retirement Obligations

The Company records a liability for asset retirement obligations at fair value in the period in which the liability is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method of the asset's useful life. Recognized asset retirement obligations relate to the plugging and abandonment of oil and natural gas wells and decommissioning of the gas gathering system. Management reviews the estimates of the timing of well abandonments as well as the estimated plugging and abandonment costs, which are discounted at the credit adjusted risk free rate. These adjustments are recorded to the asset retirement obligations with an offsetting change to oil and gas properties. An ongoing accretion expense is recognized for changes in the value of the liability as a result of the forecast inflation due to the passage of time, which is recorded in depreciation, depletion, amortization, and accretion expense in the consolidated statements of operations and comprehensive income.

Concentrations of Credit Risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative contracts. Exposure to credit risk associated with these instruments is controlled by (i) placing assets and other financial interests with credit-worthy financial institutions, (ii) maintaining policies over credit extension that include the evaluation of customers' financial condition and monitoring paying history, although the Company does not have collateral requirements and (iii) netting derivative assets and liabilities for counterparties with a legal right of offset.

At December 31, 2025 and 2024, cash and cash equivalents were primarily concentrated in one financial institution the U.S. We currently have $8.5 million in excess of the federally insured limits. The Company periodically assesses the financial condition of these institutions and believes that any possible credit risk is minimal.

For the year ended December 31, 2025, the Company had five customers that accounted for more than 90% of the total trade accounts receivable. For the year ended December 31, 2024, the Company had three customers that accounted for 89.1% of the total trade accounts receivable.

Geographic Locations of Operations

Approximately 67% and 50% of our revenue during fiscal years 2025 and 2024, respectively, was derived from natural gas production and gathering system revenues in the state of Pennsylvania. Approximately 19% and 40% of our revenue during fiscal year 2025 and 2024, respectively, was derived from oil, natural gas, and natural gas liquids revenues in the state of Texas.

As a result of this geographic concentration, we may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of crude oil or natural gas.

Income Taxes

The Company accounts for income taxes in accordance with ASC 740, Income Taxes, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial statement carrying amounts and the tax bases of assets and liabilities, and for operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply in the periods in which those temporary differences are expected to reverse. Significant judgment is required in evaluating the realizability of deferred tax assets, including the need for and amount of any valuation allowance. (see Note 10).

Foreign Currency Transactions

Even though the Canadian dollar is the functional currency of Epsilon Energy Ltd. (the parent entity), the United States dollar is the reporting currency for all of Epsilon's consolidated subsidiaries. Any gains or losses on transactions or monetary assets or liabilities in currencies other than the functional currency are included in net income in the current period. Gains and losses on translation of balances denominated in Canadian dollars, calculated using the end of the period exchange rate, are included in accumulated other comprehensive income.

Stock Based Compensation

The Company has issued time-based restricted stock units ("RSU"), performance share units ("PSU"), and dividend equivalent rights shares ("DER") to employees and directors of the Company. The fair value of the time-based RSU and the DER shares is determined using the fair value of the Company's common shares on the date of grant. The fair value of the PSUs is determined by the performance requirements. The RSU and PSU awards vest ratably over a three-year period. The DER awards vest immediately. Compensation expense and a corresponding increase to additional paid in capital are recorded over the vesting period.

Leases

The Company leases office space to be used for general, administrative, and executive offices with terms typically ranging from five to seven years, subject to certain renewal options as applicable. The Company considers renewal or termination options that are reasonably certain to be exercised in the determination of the lease term and initial measurement of lease liabilities and right-of-use assets. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term. Interest expense for finance leases is incurred based on the carrying value of the lease liability. Leases with an initial term of 12 months or less are not recorded on the Company's Consolidated Balance Sheets and lease agreements with lease and non-lease components are generally accounted for as a single lease component.

The Company determines whether a contract is, or contains, a lease at inception of the contract and whether that lease meets the classification criteria of a finance or operating lease. When available, the Company uses the rate implicit in the lease to discount lease payments to present value; however, most of the Company's leases do not provide a readily determinable implicit rate. Therefore, the Company must discount lease payments based on an estimate of its incremental borrowing rate based on prevailing financial market conditions at the later of date of adoption or lease commencement, credit analysis of comparable companies and management judgments to determine the present values of its lease payments (see Note 12).

Joint Interests

The majority of the Company's oil and natural gas exploration, development and production activities, and the gathering system, are conducted jointly with others and, accordingly, these financial statements reflect only the Company's proportionate interest in such jointly controlled assets.

Deferred Financing Costs

The Company has deferred financing costs - upfront fees and expenses that include origination, underwriting, legal and other fees – that were incurred to secure our revolving credit facility. The fees are amortized using the straight-line method, which approximates the effective interest method, over the life of the credit facility and are recognized in our consolidated statements of operations as interest expense. The unamortized deferred financing costs related to the credit facility are reported in the consolidated balance sheets as Deferred financing costs in non-current assets.

Business Combinations

The Company accounts for business combinations in accordance with FASB ASC Topic 805, Business Combinations. The Company accounts for our acquisitions that qualify as a business using the acquisition method in which the Company recognizes and measures identifiable assets acquired, liabilities assumed, and any non-controlling interest in the acquired entity at their fair values as of the acquisition date. If the set of assets and activities acquired is not considered a business, it is accounted for as an asset acquisition using a cost accumulation model. In the cost accumulation model, the cost of the acquisition, including certain transaction costs, is allocated to the assets acquired on the basis of relative fair values.

The Company includes the results of operations of acquired businesses beginning on the respective acquisition dates. In accordance with the acquisition method, the Company allocates the purchase price of an acquired business to its identifiable assets and liabilities based on the estimated fair values. The fair values of identifiable assets acquired and liabilities assumed are determined based on various valuation techniques, including market prices, discounted cash flow analysis, and independent appraisals. This fair value measurement is based on unobservable (Level 3) inputs. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. The excess value of the net identifiable assets and liabilities acquired over the purchase price of an acquired business, if any, is recorded as a bargain purchase gain. Transaction costs related to the business combination are expensed as incurred.

Recently Issued Accounting Standards

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures, which requires public entities, on an annual basis, to disclose disaggregated information about a reporting entity's effective tax rate reconciliation, using both percentages and reporting currency amounts for specific standardized categories, as well as disclosure of income taxes paid disaggregated by jurisdiction. Effective January 1, 2025, the Company adopted ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The amendments enhance income tax disclosures, primarily related to the effective tax rate reconciliation and income taxes paid. The Company adopted the amendments on a prospective basis. The adoption did not have a material impact on the Company's consolidated financial statements, as the amendments relate primarily to expanded disclosures and do not change the recognition or measurement of income taxes. Because the amendments were adopted prospectively, the enhanced disclosures required by ASU 2023-09 are provided for the year ended December 31, 2025. Prior-year disclosures continue to be presented in accordance with the Company's previously applied accounting guidance. See Note 9 "Income Taxes" in the Notes to Consolidated Financial Statements.

In March 2024, the FASB issued ASU No. 2024-01, Compensation – Stock Compensation (Topic 718): Scope Applications of Profits Interest and Similar Awards ("ASU 2024-01"). The amendments in ASU 2024-01 improves its overall clarity and operability without changing the guidance and adding illustrative examples to determine whether profits interest award should be accounted for in accordance with Topic 718. The guidance is effective for fiscal years beginning after December 15, 2024, and interim periods within those annual periods. The Company has adopted ASU No. 2024-01 as of December 31, 2025 with no material impact.

In November 2024, the FASB issued ASU 2024-3 "Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures." The ASU will improve the decision usefulness for investors by requiring public business entities to disclose more detailed information about their expenses such as (a) inventory and manufacturing expense, (b) employee compensation, (c) depreciation, (d) intangible asset amortization, etc. The amendments will be effective for fiscal years beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027, with early adoption permitted. The amendments will be applied prospectively with an option for a retrospective application. The Company is evaluating the impact of this new standard and believes that the adoption will result in additional disclosures, but will not have any other impact on its consolidated financial statements.

In July 2025, the FASB issued ASU 2025-05, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit losses for Accounts Receivable and Contract Assets. The amendments in this update provide (1) all entities with a practical expedient to assume that current conditions as of the balance sheet date do not change for the remaining life of the assets and (2) entities other than public business entities with an accounting policy election to consider collection activity after the balance sheet date when estimating expected credit losses for current accounts receivable and current contract assets arising from transactions accounted for under Topic 606. The amendments will be effective for fiscal years beginning after December 15, 2025, with early adoption permitted. The Company is evaluating the impact of this new standard and believes that the adoption may result in additional disclosures, but will not have any material impact on its consolidated financial statements.

4. Business Combination

During the year ended December 31, 2025, Epsilon acquired 100% of the ownership interest in Peak Exploration & Production LLC and Peak BLM Lease LLC and their subsidiaries (together, "Peak") for total consideration of $88.5 million consisting of 1) issuance of 5,681,489 common shares valued at $27.6 million, 2) contingent consideration of up to 2,500,000 common shares valued at $10.6 million, and the settlement of $50.3 million of debt. The contingent consideration was settled on November 19, 2025, through the issuance of 2,234,847 common shares for $10.6 million. The acquired assets primarily include operated and non-operated production and leasehold interests in the core of the Powder River Basin in Wyoming.

The following table summarizes the allocation of the total purchase price to the assets acquired and liabilities assumed based on the estimated fair value as of the closing date of the acquisition.

Purchase price allocation as of November 14, 2025:

Consideration:		
Share consideration issued to sellers November 14, 2025 - 5,681,489 common shares	$	27,555,222
Fair value of contingent share consideration (1)		10,637,872
Debt repayment		50,335,666
Total consideration transferred		88,528,760
Fair value of assets acquired:		
Cash		580,820
Oil and gas receivable		5,962,465
Joint interest billing receivable		2,717,522
Prepaid and other assets		1,045,265
Proved oil and gas properties		47,870,041
Unproved oil and gas properties		59,014,000
Land and buildings		3,664,201
Other non-current assets		1,130,472
Amount attributable to assets acquired		121,984,786
Fair value of liabilities assumed:		
Account payable		7,745,885
Revenue and production taxes payable		7,533,581
Accrued liabilities		3,966,408
Ad valorem taxes payable - current		1,830,419
ROU liability - current		150,577
Asset retirement obligations		3,815,948
Ad valorem taxes payable - long term		8,283,967
ROU liability - long term		129,241
Amount attributable to liabilities assumed		33,456,026
Net assets acquired	$	88,528,760

(1) The contingent consideration was settled on November 19, 2025. The Company issued 2,234,847 common shares with a fair value of $10.6 million.

The Company funded the acquisition through the issuance of shares and borrowings under our credit facility. The results of operations attributable to Peak since the closing date of the acquisition have been included in the consolidated statements of operations and comprehensive income and include $4 million of total revenues and a $5,747 net loss for the year ended December 31, 2025.

Pro Forma Operating Results (Unaudited)

The following supplemental, unaudited pro forma combined financial information for the year ended December 31, 2025 reflects the consolidated results of operations of the Company as if the Peak acquisition had occurred on January 1, 2024. The information below reflects pro forma adjustments based on available information and certain assumptions that the Company believes are factual and supportable. The unaudited pro forma information includes adjustments for (i) leasehold expense (ii) depreciation, depletion, amortization, and accretion, (iii) loss on impairment of long term assets, (iv) interest expense related to long term debt, and (v) loss on sale of assets. In addition, for the year ended December 31, 2025 and 2024, the pro forma information has been effected for income taxes with an effective tax rate of 6.31% and 45.79%, respectively.

(unaudited)	Year ended December 31, 2025	Year ended December 31, 2024
Total revenues	$ 83,817,737	$ 82,149,610
Net income	$ 3,716,248	$ 10,307,310
Basic net income per common share	$ 0.16	$ 0.47
Diluted net income per common share	$ 0.16	$ 0.47

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Company would have reported had the Peak acquisition been completed as of January 1, 2024, and should not be taken as indicative of the Company's future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

5. Property and Equipment

The following table summarizes the Company’s property and equipment at December 31, 2025 and 2024:

	December 31, 2025	December 31, 2024
Property and equipment:		
Oil and gas properties, successful efforts method		
Proved properties	$ 233,334,212	$ 191,879,210
Unproved properties	79,307,169	28,364,186
Accumulated depletion, depreciation, amortization and impairment	(131,636,141)	(123,281,395)
Total oil and gas properties, net	181,005,240	96,962,001
Gathering system	43,540,389	43,116,371
Accumulated depletion, depreciation, amortization and impairment	(37,472,139)	(36,449,511)
Total gathering system, net	6,068,250	6,666,860
Land	1,231,965	637,764
Buildings and other property and equipment, net	4,132,732	259,335
Total property and equipment, net	$ 192,438,187	$ 104,525,960

Asset Acquisitions

During the year ended December 31, 2025, Epsilon had no asset acquisitions.

During the year ended December 31, 2024, Epsilon made the following four acquisitions. Management determined that substantially all of the fair value of the gross assets acquired were concentrated in oil and gas properties and therefore accounted for these transactions as asset acquisitions and allocated the purchase price based on the relative fair value of the assets acquired and liabilities assumed.

- a 25% working interest in producing wells in Ector County, Texas for $12.1 million.
- a 25% working interest in undeveloped acreage in Ector County, Texas for $2.6 million.
- a 50% working interest in undeveloped acreage in Alberta, Canada for $1.0 million.
- a joint venture covering undeveloped acreage in Alberta, Canada with a commitment to provide an approximately $7.0 million drilling carry to earn a 25% working interest

Property Sale

During the year ended December 31, 2025, Epsilon sold all of its interest in Dewey Energy Holding, LLC for $2.5 million. This sale resulted in a loss of $19.3 million. During the year ended December 31, 2024, Epsilon had no asset sales.

Property Impairment

Epsilon performs a quantitative impairment test whenever events or changes in circumstances indicate that an asset group's carrying amount may not be recoverable. When indicators of impairment are present, the Company first compares expected future undiscounted cash flows by asset group to their respective carrying values. If the carrying amount exceeds the estimated undiscounted future cash flows, a reduction of the carrying amount to the estimated fair values is required. This is determined based on discounted cash flow techniques using significant assumptions including production volumes, future commodity prices, and a market-specific weighted average cost of capital which are affected by expectations about future market and economic conditions. Additionally, U.S. GAAP requires that if an exploratory well is determined not to have found proved reserves, the costs incurred, net of any salvage value, are charged to expense. For unproved properties, such as leasehold costs, expected current and future market prices for similar assets are considered relative to carrying values in evaluating impairment.

For the year ended December 31, 2025, the Company recorded an impairment of $3.2 million on the Canadian wells (2 gross, 0.5 net) and $0.7 million on the New Mexico wells (2 gross, 0.2 net) due to low forward oil prices on December 31, 2025 (which are required to be used in impairment testing) and an offset frac hit impacting production and reserves in New Mexico. During the year ended December 31, 2024, Epsilon recorded an impairment of $1.45 million on the Killam project (interest acquired in April 2024) in Alberta, Canada as a result of a decrease in forecasted reserves. Refer to Note 16 – Fair Value Measurements.

6. Revolving Line of Credit

The Company closed a new senior secured reserve based revolving credit facility on October 10, 2025 with Frost Bank as administrative agent and Frost Bank and Texas Capital Bank as lenders. As of December 31, 2025, the borrowing base was $80 million, supported by the Company's producing reserves and is subject to semi-annual redeterminations with a maturity date of October 10, 2029. Interest will be charged at the 3-month Term SOFR rate plus a margin of 3-4% (depending on facility utilization), payable quarterly. The facility is secured by the assets of the Company's Epsilon Energy USA subsidiary. During March 2026, the Company made a $5 million repayment on the outstanding credit facility.

Under the terms of the facility, the Company must adhere to the following financial covenants:

- Current ratio of 1.0 to 1.0 (current assets / current liabilities)
- Leverage ratio of less than 2.5 to 1.0 (total debt / income adjusted for interest, taxes and noncash amounts)

Additionally, the Company is required to hedge 50% of its forecasted Proved Developed Producing production over a rolling 18-month period. If the facility utilization drops below 50%, then the required hedging drops to 25% of Proved Developed Producing production for the last 6 months of the 18-month period.

We were in compliance with the financial covenants of the agreement as of December 31, 2025.

	Balance at December 31, 2025	Balance at December 31, 2024	Borrowing Base	Interest Rate
Credit facility payable	$ 50,500,000	$ —	$ 80,000,000	SOFR + 3.25%

7. Shareholders' Equity

Authorized shares

The Company is authorized to issue an unlimited number of common shares with no par value and an unlimited number of Preferred Shares with no par value.

Purchases of Equity Securities

On February 18, 2026, the Board authorized a new share repurchase program of up to 3,014,986 common shares, representing 10% of the outstanding common shares of the Company at such time, for an aggregate purchase price of not more than US $15.0 million. The program commenced on February 19, 2026 and is set to expire February 18, 2027, unless the maximum amount of common shares is purchased before then or the Board approves earlier termination.

On February 12, 2025, the Board authorized a new share repurchase program of up to 2,200,876 common shares, representing 10% of the current outstanding common shares of Epsilon, for an aggregate purchase price of not more than US $13.0 million. The program commenced on February 12, 2025 and expired on February 11, 2026.

On March 19, 2024, the Board of Directors authorized a new share repurchase program of up to 2,191,320 common shares, representing 10% of the outstanding common shares of Epsilon at such time, for an aggregate purchase price of not more than US $12.0 million. The program commenced on March 27, 2024 and expired on February 12, 2025, when the Board terminated and revoked authority under the program. During the year ended December 31, 2024, we repurchased 125,000 common shares and spent $627,500 at an average price of $5.00 per share (excluding commissions) under the plan.

In 2024, the Company also repurchased 248,700 common shares and spent $1,203,708 at an average price of $4.82 per share (excluding commissions) and retired 319,574 common shares under the 2023-2024 repurchase program before the plan terminated on March 26, 2024. During the year ended December 31, 2024, the Company repurchased a total of 373,700 shares and spent $1,831,208 at an average price of $4.88 per share (excluding commissions) under the two previous repurchase programs.

Equity Incentive Plan

The Board adopted the 2020 Equity Incentive Plan (the "2020 Plan") on July 22, 2020 subject to approval by Epsilon's shareholders at Epsilon's 2020 Annual General and Special Meeting of shareholders, which occurred on September 1, 2020 (the "Meeting"). Shareholders approved the 2020 Plan at the Meeting.

The 2020 Plan provides for incentive compensation in the form of stock options, stock appreciation rights, restricted stock and stock units, performance shares and units, dividend equivalent rights, other stock-based awards and cash-based awards. Under the 2020 Plan, Epsilon is authorized to issue up to 2,000,000 common shares.

Restricted Stock Unit

For the year ended December 31, 2025, 488,283 restricted common shares with a weighted average grant date fair value of $4.78 were awarded to the Company's management, employees, and board of directors. For the year ended December 31, 2024, 300,052 restricted common shares with a weighted average grant date fair value of $5.97 were awarded to the Company's management, employees, and board of directors. These shares vest over a three or four-year period, with an equal number of shares being issued per period on the anniversary of the award resolution. The vesting of the shares is contingent on the individuals' continued employment or service. The Company determined the fair value of the granted Restricted Stock-based on the market price of the common shares of the Company on the date of grant.

The following table summarizes restricted stock for the years ended December 31, 2025 and 2024:

	Year ended December 31, 2025			Year ended December 31, 2024		
	Number of Restricted Shares Outstanding	Weighted Average Remaining Life (years)	Weighted Average Grant Date Fair Value	Number of Restricted Shares Outstanding	Weighted Average Remaining Life (years)	Weighted Average Grant Date Fair Value
Balance non-vested Restricted Stock at beginning of period	560,970	1.61	$ 5.77	491,536	1.74	$ 5.59
Granted	488,283	1.50	4.78	300,052	1.92	5.97
Vested	(267,461)	—	5.60	(230,618)	—	5.65
Balance non-vested Restricted Stock at end of period	781,792	1.71	$ 5.06	560,970	1.61	$ 5.77

Stock compensation expense for the granted Restricted Stock is recognized over the vesting period. Stock compensation expense recognized during the year ended December 31, 2025 was $1,524,902 (during the year ended December 31, 2024, $1,244,416). The total fair value of vested shares during the year ended December 31, 2025 was $1,763,433 (during the year ended December 31, 2024: $1,303,187).

At December 31, 2025, the Company had unrecognized stock-based compensation related to these shares of $4,146,227 to be recognized over a weighted-average period of 1.37 years.

Dividend Equivalent Rights

Per the 2020 Plan, all employees and directors are entitled to Dividend Equivalent Rights with respect to the payment of cash dividends on Common Shares during the period beginning on the grant date of this award and ending, with respect to each share subject to the award, on the earlier of the date the Award is settled or the date on which it is terminated. Dividend Equivalent Rights shall be paid by crediting the holder with a cash amount or with additional whole RSUs within 30 days of the date of payment of such cash dividends on Common Shares, as determined by the Committee, subject to the holder's continued service with the Company. Such cash amount or additional RSUs shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the RSUs originally subject to this Award.

For the year ended December 31, 2025, 47,417 common shares were issued as dividend equivalent rights. Stock compensation expense recognized during the year ended December 31, 2025 was $200,015.

8. Revenue Recognition

Revenues are comprised primarily of sales of natural gas, oil and NGLs, along with the revenue generated from the Company's ownership interest in the Auburn GGS in Pennsylvania.

Overall, product sales revenue generally is recorded in the month when contractual delivery obligations are satisfied, which occurs when control is transferred to the Company's customers at delivery points based on contractual terms and conditions. In addition, gathering and compression revenue generally is recorded in the month when contractual service obligations are satisfied, which occurs as control of those services is transferred to the Company's customers. Gathering System revenues derived from Epsilon's production, which have been eliminated from total gathering system revenues ("elimination entry"), amounted to $1.9 million and $1.1 million, respectively, for the years ended December 31, 2025 and 2024.

The following table details revenue for the years ended December 31, 2025 and 2024:

	Year Ended December 31, 2025	Year Ended December 31, 2024
Revenue		
Natural gas	$ 29,121,446	$ 10,786,068
Natural gas liquids	1,978,860	1,481,958
Oil and condensate	13,803,515	13,730,686
Gathering and compression fees (1)	6,683,735	5,524,063
Total revenue	$ 51,587,556	$ 31,522,775

(1) Net of elimination

Product Sales Revenue

The Company enters into contracts with third-party purchasers to sell its natural gas, oil, NGLs and condensate production. Under these product sales arrangements, the sale of each unit of product represents a distinct performance obligation. Product sales revenue is recognized at the point in time that control of the product transfers to the purchaser based on contractual terms which reflect prevailing commodity market prices. To the extent that marketing costs are incurred by the Company prior to the transfer of control of the product, those costs are included in lease operating expenses on the Company's consolidated statements of operations and comprehensive income.

Settlement statements for product sales, and the related cash consideration, are generally received from the purchaser within 30 days. For operated production in Wyoming, cash consideration is typically received within 30 days after the end of a production month for oil, while natural gas and NGLs cash consideration is typically received within 60 days after the end of a production month. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for sale of the natural gas, oil, NGLs, or condensate. Estimated revenue due to the Company is recorded within the receivables line item on the accompanying consolidated balance sheets until payment is received.

Gas Gathering and Compression Revenue

The Company also provides natural gas gathering and compression services through its ownership interest in the Auburn GGS in Pennsylvania. For the provision of gas gathering and compression services, the Company collects its share of the gathering and compression fees per unit of gas serviced and recognizes gathering revenue over time using an output method based on units of gas gathered.

The settlement statement from the operator of the Auburn GGS is received two months after transmission and compression has occurred. As a result, the Company must estimate the amount of production that was transmitted and compressed within the system. Estimated revenue due to the Company is recorded within the receivables line item on the accompanying consolidated balance sheets until payment is received.

Current Expected Credit Losses

Under ASU 326, Financial Instruments – Credit Losses, estimated losses on financial assets are provided through an allowance for credit losses. We also have accounts receivable which are primarily from purchasers of oil and natural gas, counterparties to our financial instruments, and revenues earned for compression and gathering services. Our oil, gas, and natural gas liquids accounts receivables are generally collected within 30 days after the end of the month. Compression and gathering receivables are generally collected within 60 days after the end of the month. We assess collectability through various procedures, including review of our trade receivable balances by counterparty, assessing economic events and conditions, our historical experience with counterparties, the counterparty's financial condition and the amount and age of past due accounts. As of December 31, 2025 and 2024, we determined that our allowance for credit loss was nil.

The following table details accounts receivable as of December 31, 2025, 2024 and 2023:

	December 31, 2025	December 31, 2024	December 31, 2023
Accounts receivable			
Natural gas and oil sales	$ 10,848,263	$ 4,888,294	$ 4,327,886
Joint interest billing	3,603,864	—	17,476
Gathering and compression fees	1,307,947	918,471	1,543,239
Commodity contract	167,636	36,957	72,075
Interest	—	—	54,772
Other receivables	204,791	—	—
Total accounts receivable	$ 16,132,501	$ 5,843,722	$ 6,015,448

9. Accumulated Other Comprehensive Income

Accumulated other comprehensive income includes certain transactions that have generally been reported in the consolidated statements of changes in shareholders' equity. The activity in accumulated other comprehensive income during the years ended December 31, 2025 and 2024 consisted of the following:

	Year Ended December 31, 2025	Year Ended December 31, 2024
Balance at beginning of period	$ 10,033,267	$ 9,772,277
Translation (loss)/gain	(136,700)	262,588
Unrealized gain/(loss) on securities	—	(1,598)
Balance at end of period	$ 9,896,567	$ 10,033,267

10. Income Taxes

Net income (loss) before income taxes is as follows for the periods indicated:

	Year ended December 31, 2025	Year ended December 31, 2024
Foreign	$ (5,002,874)	$ (2,769,534)
U.S.	(433,258)	6,326,427
	$ (5,436,132)	$ 3,556,893

We file income tax returns in the United States, Canada, and various state and local jurisdictions.

We believe that we have appropriate support for the income tax positions taken and to be taken on the Company's tax returns and that the accruals for tax liabilities are adequate for all open years based on our assessment of many factors including past experience and interpretations of tax law applied to the facts of each matter. The Company's tax returns are open to audit under the statute of limitations for the years ending December 31, 2021 through December 31, 2025.

The following tables present the Company's current and deferred tax (benefit) expense for the periods indicated:

	Year ended December 31, 2025	Year ended December 31, 2024
Current:		
Federal	$ 218,565	$ 391,009
State	16,235	53,450
Foreign	10,923	—
Total current income tax expense	245,723	444,459
Deferred:		
Federal	(96,957)	1,372,363
State	213,965	(187,729)
Total deferred tax expense	117,008	1,184,634
Income tax expense	$ 362,731	$ 1,629,093

The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate to the income tax provision in our financial statements. Our effective tax rate for 2025 differs from the statutory rate primarily due to states taxes, foreign withholding taxes, and the recognition of a valuation allowance on our Canadian and Oklahoma state deferred tax assets.

	Year Ended December 31, 2025	Effective Tax Rate
US Federal Statutory Tax Rate	$ (1,141,588)	21.00 %
State and Local Income Taxes, Net of Federal Income Tax Effect*	226,790	(4.17)%
Foreign Tax Effects		
Canada		
Statutory tax rate difference between Canada and United States	(467,456)	8.60 %
US withholding tax on dividends from United States to Canada	248,783	(4.58)%
Changes in valuation allowance	1,144,121	(21.05)%
Other	(26,291)	0.48 %
Alberta		
Statutory tax rate difference between Alberta and United States	(195,946)	3.60 %
Changes in valuation allowance	610,198	(11.22)%
Other	(14,022)	0.26 %
Nontaxable or Nondeductible Items		
Other	(21,858)	0.40 %
Income tax expense	$ 362,731	(6.68)%

*State taxes in Pennsylvania made up the majority (greater than 50 percent) of the tax effect in this category.

Our effective tax rate for 2024 differs from the statutory rate primarily due to states taxes, foreign withholding taxes, & the recognition of a valuation allowance on our Canadian and Oklahoma state deferred tax assets. Our effective tax rate for 2024, excluding the impact of Canadian loss net valuation allowance, is 25.48%.

		Year Ended December 31, 2024	Effective Tax Rate
Income tax provision computed at the statutory federal tax rate	$	746,947	21.00 %
Difference in Canadian and U.S. tax rate		(55,391)	(1.56)%
Adjustment of Canadian deferred tax balances		983,975	27.66 %
Valuation allowance on Canadian loss		(425,667)	(11.97)%
Return to provision adjustment		(1,245)	(0.04)%
State taxes		(129,233)	(3.63)%
State valuation allowance		(16,271)	(0.46)%
Foreign withholding on dividends		414,250	11.65 %
Miscellaneous other items		111,728	3.14 %
Income tax expense	$	1,629,093	45.79 %

Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes.

Net deferred tax liabilities consisted of the following at December 31, 2025 and 2024:

	As of December 31,			
		2025		2024
Deferred tax assets:				
US Federal and state net operating loss carryforwards	$	2,030,390	$	358,224
Canadian net operating loss carryforwards		12,839,073		11,084,754
ARO		1,768,208		873,169
Lease Liabilities		87,015		114,196
Other		275,810		159,582
Unrealized derivatives		—		116,743
Gross deferred tax assets		17,000,496		12,706,668
Valuation allowance		(13,258,688)		(11,213,899)
Total net deferred tax assets		3,741,808		1,492,769
Deferred tax liabilities:				
Oil and gas property		(14,184,652)		(12,620,466)
Partnership		(1,413,943)		(1,528,368)
ROU Assets		(60,811)		(82,512)
Unrealized derivatives		(937,987)		—
Gross deferred tax liabilities		(16,597,393)		(14,231,346)
Net deferred tax liability	$	(12,855,585)	$	(12,738,577)

As of December 31, 2025, we have $1.4 million of U.S. federal net operating loss carry-forwards, all of which has an indefinite carryforward period but is limited to offset 80% of taxable income in any future year. We also have approximately $30.8 million of state net operating loss carry-forwards (tax-effected $0.6 million), of which $0.2 million expires in 2037 and the remaining can be carried forward indefinitely. These loss carryforwards may reduce future taxable income, however, the extent of which may be limited in the circumstances that an IRC Section 382 limitation would apply due to an ownership change. A state valuation allowance of $0.4 million is applicable to the net state deferred tax assets attributable to Oklahoma because of objective negative evidence on the cumulative loss incurred in the state over the three-year period ended December 31, 2025. As of December 31, 2025, we have $48.2 million (tax-effected 11.1 million) of Canadian net operating loss carry-forwards. A separate valuation allowance of $12.8 million attributable to Canadian net operating losses and other tax carryovers is recorded because it is more likely than not to be utilized.

The Company does not have any material uncertain tax positions. The Company recognizes interest expense and penalties related to the uncertain tax position in the income tax expense line in the accompanying consolidated statements of operations and comprehensive loss. Accrued interest and penalties are included in other non-current liabilities in the consolidated balance sheet and were $0 as of December 31, 2025 and 2024.

Total net income tax payments were $2.2 million for the year ended December 31, 2025. The following table lists the components of the payments for income taxes:

	Year Ended December 31, 2025
US Federal	$ 1,417,860
State	
Pennsylvania	755,138
Other	3,986
Total net payments	$ 2,176,984

11. Commitments and Contingencies

The Company also enters into commitments for capital expenditures in advance of the expenditures being made. As of December 31, 2025, our commitments for capital expenditures were $3.8 million related to drilling costs.

Litigation

In 2025, the Company filed a lawsuit against a contractor regarding alleged non-performance while running casing in a well. The Company is seeking damages due to its inability to complete the Leavitt Fed 2-9-4MH well. The Company is in the process of scheduling arbitration

The Company has intervened as a defendant-intervenor in litigation challenging BLM’s issuance of federal oil and gas leases acquired by the Company in 2017, 2018, and 2020. Plaintiffs allege deficiencies in BLM’s environmental review under NEPA. The Company intervened to protect its leasehold interests. Management does not believe the outcome will have a material adverse effect on the Company’s financial position.

Between September 30, 2025 and October 28, 2025, we received multiple demand letters on behalf of purported Epsilon stockholders (the "Demands”). The Demands primarily alleged that the Preliminary Proxy Statement filed on September 19, 2025 or the Definitive Proxy Statement filed on October 10, 2025, as applicable, failed to disclose certain material information with respect to the acquisition of Peak Exploration and Production, LLC, and Peak BLM Lease LLC.

On October 16, 2025, we received a copy of a complaint filed against Epsilon and certain members of Epsilon’s Board of Directors in the Supreme Court of the State of New York, County of New York, on behalf of purported Epsilon stockholder Anthony Morgan (the "Morgan Complaint”). On October 17, 2025, we received a copy of a complaint filed against Epsilon and certain members of Epsilon’s Board of Directors in the Supreme Court of the State of New York, County of New York, on behalf of purported Epsilon stockholder Richard Lawrence (the "Lawrence Complaint,” and together with the Morgan Complaint, the "Complaints”).

The Complaints allege, among other things, that Epsilon and the other named defendants (the "Epsilon Defendants”) violated New York common law based on claims of negligence, negligent misrepresentation and concealment. Specifically, the Complaints allege that the Preliminary Proxy Statement or the Definitive Proxy Statement, as applicable, failed to disclose, among other things, certain details regarding the background of the Transactions. Among other remedies, the Complaints sought an injunction against consummating the Transactions, rescission or actual and punitive damages if the Transactions are consummated, costs and attorneys’ fees. To date, we have not been served with the Complaints, and the Plaintiffs have not taken any additional steps in furtherance of prosecuting the Complaints.

While we believe that the disclosures set forth in the Preliminary Proxy Statement and the Definitive Proxy Statement comply fully with applicable law, to moot certain of the claims made in the Demands and Complaints, to avoid nuisance and potential expense and delay, we voluntarily supplemented the Definitive Proxy Statement with certain disclosures in our Supplemental Disclosures to Definitive Proxy Statement filed on October 31, 2025. Nothing in our

Supplemental Disclosures was an admission of the legal necessity or materiality under applicable law of any of the disclosures set forth in the Preliminary Proxy Statement or the Definitive Proxy Statement. To the contrary, we deny all allegations in the Demands and Complaints that any additional disclosure was required.

12. Leases

Under ASC 842, Leases, the Company recognized an operating lease related to its corporate office as of December 31, 2025 summarized in the following table:

	December 31, 2025	December 31, 2024
Asset		
Operating lease right-of-use assets, long term	$ 488,949	$ 344,589
Total operating lease right-of-use assets	$ 488,949	$ 344,589
Liabilities		
Operating lease liabilities	$ 271,494	$ 121,135
Operating lease liabilities, long term	340,052	355,776
Total operating lease liabilities	$ 611,546	$ 476,911
Operating lease costs	$ 269,910	$ 236,044
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from operating leases	$ 316,435	$ 214,230
Weighted average remaining lease term (years) - operating lease	1.86	2.50
Weighted average discount rate (annualized) - operating lease	8.25%	8.25%

On March 1, 2023, the Company commenced a new office lease with a 70 month lease term and future lease payments estimated to be approximately $0.85 million. Through its subsidiaries, the Company also leases office space in both Englewood, CO and Wright, WY. Lease expense for operating leases was $0.27 million and $0.24 for the years ended December 31, 2025 and 2024, respectively. This lease expense is presented in other general and administrative expenses in the consolidated statements of operations and comprehensive income.

Future minimum lease payments as of December 31, 2025 are as follows:

	Operating Leases
2026	$ 334,155
2027	282,059
2028	183,963
Total minimum lease payments	800,177
Less: imputed interest	(188,631)
Present value of future minimum lease payments	611,546
Less: current obligations under leases	(271,494)
Long-term lease obligations	$ 340,052

13. Net Income Per Share

Basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the period. Diluted net income per share is computed based upon the weighted-average number of common shares outstanding during the period plus the assumed issuance of common shares for all potentially dilutive securities.

The net income used in the calculation of basic and diluted net income per share are as follows:

	Year ended December 31, 2025	Year ended December 31, 2024
Net (loss) income	$ (5,798,863)	$ 1,927,800

In calculating the net income per share, basic and diluted, the following weighted-average shares were used:

	Year ended December 31, 2025	Year ended December 31, 2024
Basic weighted-average number of shares outstanding	23,020,672	21,930,277
Unvested time-based restricted shares	—	—
Diluted weighted-average shares outstanding	23,020,672	21,930,277

We excluded the following shares from the diluted net income per share because their inclusion would have been anti-dilutive.

	Year ended December 31, 2025	Year ended December 31, 2024
Anti-dilutive unvested time-based restricted shares	531,610	512,072

14. Operating Segments

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision-maker (CODM). The CODM, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as executive management consisting of the Chief Executive Officer, Chief Financial Officer, and Chief Operating Officer. The CODM uses the Company's consolidated financial results, including operating income or loss by segment, to make key operating decisions, assess performance, and to allocate resources. Segment performance is evaluated based on operating income or loss as shown in the table below. Interest income and income taxes are managed separately on a group basis.

The Company's reportable segments are as follows:

a. The Upstream segment activities include acquisition, development and production of natural gas and oil reserves on properties within the United States and Canada; and
b. The Gas Gathering segment partners with two other companies to operate a natural gas gathering system.

Segment activity as of, and for the years ended December 31, 2025 and 2024 is as follows:

	Upstream	Gas Gathering	Total
As of and for the year ended December 31, 2025			
Operating revenue			
Natural gas	$ 29,121,446	$ —	$ 29,121,446
Natural gas liquids	1,978,860	—	1,978,860
Oil and condensate	13,803,515	—	13,803,515
Gathering and compression fees	—	6,683,735	6,683,735
Intersegment gathering and compression fees	—	1,864,769	1,864,769
	44,903,821	8,548,504	53,452,325
Reconciliation of operating revenue			
Elimination of intersegment revenues			(1,864,769)
Total consolidated operating revenue(1)(3)			51,587,556
Operating costs			
Gathering, transportation, and compression	7,836,882	—	7,836,882
Other lease operating expense	4,681,443	—	4,681,443
Gathering system operating expenses	—	2,362,036	2,362,036
Intersegment other lease operating expense	1,864,769	—	1,864,769
Impairment	3,936,669	—	3,936,669
Loss on sale of oil and gas properties	19,256,530	—	19,256,530
Depletion, depreciation, amortization and accretion	11,139,747	1,030,573	12,170,320
Segment operating (loss) income	$ (3,812,219)	$ 5,155,895	$ (521,093)
Reconciliation of segment operating loss			
Salary expense			(3,876,611)
Stock based compensation			(1,744,917)
Transaction costs			(2,947,907)
Other general and administrative			(3,291,624)
Elimination of intersegment other lease operating expenses			1,864,769
Interest income			188,369
Interest expense			(624,160)
Gain on derivative contracts			5,500,486
Other income			16,556
Net loss before income tax expense			$ (5,436,132)
Capital expenditures (2)	$ 14,374,208	$ 465,203	$ 14,839,411
Segment assets (3)	$ 181,251,460	$ 6,068,250	$ 187,319,710
Total segment assets reconciled to consolidated amounts are as follows:			
Total segment assets			$ 187,319,710
Current assets, net			32,583,778
Fair value of derivatives, long term			1,154,936
Other property and equipment			5,364,697
Operating lease right-of-use asset			488,949
Credit facility fees			774,347
Restricted Cash			553,000
Total assets			$ 228,239,417

	Upstream	Gas Gathering	Total
As of and for the year ended December 31, 2024			
Operating revenue			
Natural gas	$ 10,786,068	$ —	$ 10,786,068
Natural gas liquids	1,481,958	—	1,481,958
Oil and condensate	13,730,686	—	13,730,686
Gathering and compression fees	—	5,524,063	5,524,063
Intersegment gathering and compression fees	—	1,135,176	1,135,176
	25,998,712	6,659,239	32,657,951
Reconciliation of operating revenue			
Elimination of intersegment revenues			(1,135,176)
Total consolidated operating revenue(1)(3)			31,522,775
Operating costs			
Gathering, transportation, and compression	4,996,764	—	4,996,764
Other lease operating expense	2,268,060	—	2,268,060
Gathering system operating expenses	—	2,265,190	2,265,190
Intersegment other lease operating expense	1,135,176	—	1,135,176
Impairment	1,450,076	—	1,450,076
Depletion, depreciation, amortization and accretion	9,275,604	909,515	10,185,119
Segment operating income	$ 6,873,032	$ 3,484,534	$ 9,222,390
Reconciliation of segment operating income			
Salary expense			(2,815,428)
Stock based compensation			(1,244,416)
Other general and administrative			(2,873,286)
Elimination of intersegment other lease operating expenses			1,135,176
Interest income			493,277
Interest expense			(46,400)
Loss on derivative contracts			(391,147)
Other income			76,727
Net income before income tax expense			$ 3,556,893
Capital expenditures (2)	$ 36,219,444	$ 341,452	$ 36,560,896
Segment assets (3)	$ 97,944,718	$ 6,666,860	$ 104,611,578
Total segment assets reconciled to consolidated amounts are as follows:			
Total segment assets			$ 104,611,578
Current assets, net			14,131,519
Other property and equipment			897,099
Operating lease right-of-use asset			344,589
Restricted cash			470,000
Total assets			$ 120,454,785

(1) Segment operating revenue represents revenues generated from the operations of the segment. Inter-segment sales during the years ended December 31, 2025 and 2024 have been eliminated upon consolidation. For the year ended December 31, 2025, three purchasers each accounted for 10% or more of our total revenue: ARM Energy (55%) and Ares Energy (20%) from the upstream segment and Williams (17%) from the gas gathering segment. For the year ended December 31, 2024, three purchasers each accounted for 10% or more of our total revenue: ARM Energy (30%) and Ares Energy (38%) from the upstream segment and Williams (20%) from the gas gathering segment.

(2) Capital expenditures for the Upstream segment consist primarily of the acquisition of properties, and the drilling and completing of wells while Gas Gathering consists of expenditures relating to the expansion, completion, and maintenance of the gathering and compression facility.

(3) Our upstream segment includes Canadian revenue and assets for the year ended December 31, 2025 of $1.0 million and $6.6 million, respectively. Our upstream segment includes Canadian revenue and assets for the year ended December 31, 2024 of $0.1 million and $3.7 million, respectively.

15. Commodity Risk Management Activities

Commodity Price Risks

Epsilon engages in price risk management activities from time to time. These activities are intended to manage Epsilon's exposure to fluctuations in commodity prices for natural gas and oil by securing fixed price contracts for a portion of expected sales volumes.

Inherent in the Company's fixed price contracts, are certain business risks, including market risk and credit risk. Market risk is the risk that the price of oil and natural gas will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the Company's counterparty to a contract. The Company may be required to post collateral depending on the cumulative balance owed to a counterparty on a mark-to-market basis.

The Company enters into certain commodity derivative instruments to mitigate commodity price risk associated with a portion of its future natural gas and oil production and related cash flows. The natural gas and oil revenues and cash flows are affected by changes in commodity product prices, which are volatile and cannot be accurately predicted. The objective for holding these commodity derivatives is to protect the operating revenues and cash flows related to a portion of the future natural gas and oil sales from the risk of significant declines in commodity prices, which helps ensure the Company's ability to fund the capital budget.

Epsilon has historically elected not to designate any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounts for these financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as *(loss) gain on derivative contracts* on the consolidated statements of operations and comprehensive income. The related cash flow impact is reflected in cash flows from operating activities. During 2025, Epsilon recognized gains on financial commodity derivative contracts of $5,500,486. This amount included cash received on the settlement of these contracts of $1,163,662. During 2024, Epsilon recognized losses on financial commodity derivative contracts of $391,147. This amount included cash received on the settlement of these contracts of $1,196,656.

Commodity Derivative Contracts

At December 31, 2025, the Company had outstanding NYMEX HH swaps totaling 1.68 Bcf, NYMEX HH options totaling 4.51 Bcf, NYMEX WTI CMA swaps totaling 340,916 Bbls, and NYMEX WTI CMA options totaling 181,634 Bbls for the contract period of January 2026 to January 2028.

At December 31, 2024, the Company had outstanding NYMEX HH swaps totaling 2.2615 Bcf and Tennessee Z4 basis swaps totaling 2.2615 Bcf for the contract period of January 2025 to October 2025, and NYMEX WTI CMA swaps totaling 20,662 Bbls for the contract period of January 2026 to June 2025.

	Fair Value of Derivative Assets	
	December 31, 2025	December 31, 2024
Current		
NYMEX Henry Hub (LD) Options Call	$ —	$ 151,274
NYMEX Henry Hub (LD) Options Put	709,792	—
NYMEX Henry Hub (LD) Swaps	683,222	195,211
NYMEX WTI CMA Options Put	313,499	—
NYMEX WTI CMA Swaps	1,398,169	56,547
Long-term		
NYMEX Henry Hub (LD) Options Put	647,795	—
NYMEX Henry Hub (LD) Swaps	28,058	—
NYMEX WTI CMA Options Put	900,856	—
NYMEX WTI CMA Swaps	719,912	—
	$ 5,401,303	$ 403,032

	Fair Value of Derivative Liabilities	
	December 31, 2025	December 31, 2024
Current		
NYMEX Henry Hub (LD) Options Call	$ (295,384)	$ (448,852)
NYMEX Henry Hub (LD) Swaps	(51,081)	(441,728)
NYMEX WTI CMA Options Call	(63,877)	—
Long-term		
NYMEX Henry Hub (LD) Options Call	(654,616)	—
NYMEX Henry Hub (LD) Swaps	(68,457)	—
NYMEX WTI CMA Options Call	(418,612)	—
	$ (1,552,027)	$ (890,580)
Net Fair Value of Derivatives	$ 3,849,276	$ (487,548)
Net Current	$ 2,694,340	$ (487,548)
Net Long-Term	$ 1,154,936	$ —

The following table presents the changes in the fair value of Epsilon's commodity derivatives for the periods indicated:

	Year ended December 31,	
	2025	2024
Fair value of asset (liability), beginning of the period	$ (487,548)	$ 1,100,255
Gain on derivative contracts included in earnings	5,500,486	(391,147)
Settlement of commodity derivative contracts	(1,163,662)	(1,196,656)
Fair value of asset, end of the period	$ 3,849,276	$ (487,548)

The following table presents the fair value of derivatives, as presented in the Consolidated Balance Sheets, on a net basis as they are subject to master netting arrangements:

	December 31, 2025			December 31, 2024		
	Gross Fair Value	Amounts Netted	Net Fair Value	Gross Fair Value	Amounts Netted	Net Fair Value
Derivative Assets						
Fair value of derivatives	$ 5,401,303	$ (1,552,027)	$ 3,849,276	$ 403,032	$ (403,032)	$ -
Derivative Liabilities						
Fair value of derivatives	$ (1,552,027)	$ 1,552,027	$ -	$ (890,580)	$ 403,032	$ (487,548)

16. Asset Retirement Obligations

Asset retirement obligations are estimated by management based on Epsilon's net ownership interest in all wells and the gathering system, estimated costs to reclaim and abandon such assets and the estimated timing of the costs to be incurred in future periods, and the forecast risk free cost of capital. Epsilon has estimated the net present value of its total asset retirement obligations to be $7.4 million as of December 31, 2025 ($3.7 million at December 31, 2024). We acquired $3.8 million of additional asset retirement obligation with the Peak acquisition. Each year we review, and to the extent necessary, revise our asset retirement obligations estimates in accordance with recent activity and current service costs.

The following table presents the activity in Epsilon's asset retirement obligations for the periods indicated:

	Year Ended December 31, 2025	Year ended December 31, 2024
Balance beginning of period	$ 3,652,296	$ 3,502,952
Liabilities acquired	3,841,144	48,207
Liabilities disposed of	(287,716)	—
Wells plugged and abandoned	(1,600)	(88,992)
Change in estimates	—	6,695
Accretion	233,836	183,434
Balance end of period	$ 7,437,960	$ 3,652,296

17. Fair Value Measurements

The methodologies used to determine the fair value of our financial assets and liabilities at December 31, 2025 were the same as those used at December 31, 2024.

Cash, restricted cash, accounts receivable, and accounts payable are carried at cost, which approximates fair value because of the short term maturity of these instruments. Cash equivalents from the Company's money market accounts are carried at fair value. The Company's revolving line of credit has a recorded value that approximates its fair value since its variable interest rate is tied to current market rates and the applicable margins represent market rates. The revolving line of credit is classified within Level 2 of the fair value hierarchy.

Commodity derivative instruments consist of NYMEX HH swap and option contracts and basis swap contracts for natural gas and NYMEX WTI CMA swap and option contracts for crude oil. The Company's derivative contracts are valued based on a marked to market approach. These assumptions are observable in the marketplace throughout the full term of the contract, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace, and are therefore designated as Level 2 within the valuation hierarchy. The Company utilizes its counterparties' valuations to assess the reasonableness of its own valuations.

	December 31, 2025				
	Level 1	Level 2	Level 3	Effect of Netting	Net Fair Value
Assets					
Derivative contracts	$ —	$ 5,401,303	$ —	$ (1,552,027)	$ 3,849,276
Cash equivalents	$ 181,076	$ —	$ —	$ —	$ 181,076
Liabilities					
Derivative contracts	$ —	$ 1,552,027	$ —	$ (1,552,027)	$ —

	December 31, 2024				
	Level 1	Level 2	Level 3	Effect of Netting	Net Fair Value
Assets					
Derivative contracts	$ —	$ 403,032	$ —	$ (403,032)	$ —
Cash equivalents	$ 298,767	$ —	$ —	$ —	$ 298,767
Liabilities					
Derivative contracts	$ —	$ 890,580	$ —	$ (403,032)	$ 487,548

Non-Recurring Fair Value Measurements

For the year ended December 31, 2025, the Company performed an impairment test on our oil and gas properties and it was determined that the carrying amount in New Mexico and Canada each exceeded the estimated undiscounted future cash flows resulting in a reduction of the carrying amount of the oil properties to their estimated fair values by $3.9 million. Fair value is determined using management's best estimate of proved reserves and net cash flows by area, using forward commodity prices from the last day of the year. The undiscounted future net cash flows are compared to the carrying value of each area. This nonrecurring fair value measurement is classified within Level 3 of the fair value hierarchy.

The table below summarizes the fair value of the impaired assets as of the fair value measurement date, December 31, 2025.

	December 31, 2025	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Nonrecurring fair value measurement				
Long-lived assets held and used	$ 1,110,288	$ —	$ —	$ 1,110,288
Total Nonrecurring fair value measurement	$ 1,110,288	$ —	$ —	$ 1,110,288

For the year ended December 31, 2024, the Company performed an impairment test on our oil and gas properties and it was determined that the carrying amount of the Killam project in Alberta, Canada exceeded the estimated undiscounted future cash flows resulting in a reduction of the carrying amount of the oil properties to their estimated fair values by $1.45 million. Fair value is determined using management's best estimate of proved reserves and net cash flows by area, using forward commodity prices from the last day of the year. The undiscounted future net cash flows are compared to the carrying value of each area. This nonrecurring fair value measurement is classified within Level 3 of the fair value hierarchy.

The table below summarizes the fair value of the impaired assets as of the fair value measurement date, December 31, 2024.

	December 31, 2024	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Nonrecurring fair value measurement				
Long-lived assets held and used	$ 492,253	$ —	$ —	$ 492,253
Total Nonrecurring fair value measurement	$ 492,253	$ —	$ —	$ 492,253

SUPPLEMENTAL NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

Natural Gas and Oil Reserves

Users of this information should be aware that the process of estimating quantities of “proved”, “proved developed” and “proved undeveloped” crude oil, natural gas liquids (NGLs) and natural gas reserves is complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity; evolving production history; crude oil and condensate, NGL and natural gas prices; and continual reassessment of the viability of production under varying economic conditions.

Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time. Although reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of crude oil, NGLs and natural gas, which, by analysis of geoscience and engineering data, can be estimated, with reasonable certainty, to be economically producible from a given date forward from known reservoirs under then-existing economic conditions, operating methods and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved developed reserves are proved reserves expected to be recovered under operating methods being utilized at the time the estimates were made, through wells and equipment in place or if the cost of any required equipment is relatively minor compared to the cost of a new well.

Proved undeveloped reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. PUDs can be recorded in respect of a particular undrilled location only if the location is scheduled, under the then-current drilling and development plan, to be drilled within five years from the date that the PUDs are to be recorded, unless specific factors (such as those described in interpretative guidance issued by the Staff of the SEC) justify a longer timeframe. Likewise, absent any such specific factors, PUDs associated with a particular undeveloped drilling location shall be removed from the estimates of proved reserves if the location is scheduled, under the then-current drilling and development plan, to be drilled on a date that is beyond five years from the date that the PUDs were recorded. Epsilon has formulated development plans for all drilling locations associated with its PUDs at December 31, 2025. Under these plans, each PUD location will be drilled within five years from the date it was recorded.

Estimates for PUDs are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

The following tables set forth Epsilon’s net proved reserves at December 31, 2025 and 2024 and changes for each of the two years in the year ended December 31, 2025. Net proved reserves at December 31 are estimated by the Company’s independent petroleum engineers, DeGolyer and MacNaughton for Pennsylvania, Texas, New Mexico, and Canada. Net proved reserves at December 31 are estimated by the Company’s independent petroleum engineers, Cawley, Gillespie & Associates for Wyoming.

NET PROVED RESERVE SUMMARY

	Pennsylvania	Permian Basin	Oklahoma	Wyoming	Canada	Total
Natural Gas (MMcf)						
Net proved reserves at December 31, 2023	61,760	481	3,674	-	-	65,915
Revisions of previous estimates	8,334	303	(480)	-	-	8,157
Acquisitions	-	1,471	-	-	-	1,471
Production	(5,700)	(205)	(237)	-	-	(6,142)
Net proved reserves at December 31, 2024	64,394	2,050	2,957	-	-	69,401
Revisions of previous estimates	13,100	(299)	-	-	-	12,801
Acquisitions	-	-	-	16,774	157	16,931
Divestitures	-	-	(2,760)	-	-	(2,760)
Production	(9,402)	(161)	(197)	(189)	(52)	(10,001)
Net proved reserves at December 31, 2025	68,092	1,590	-	16,585	105	86,372
Natural Gas Liquids (MBbl)						
Net proved reserves at December 31, 2023	-	116	267	-	-	383
Revisions of previous estimates	-	89	(1)	-	-	88
Acquisitions	-	475	-	-	-	475
Production	-	(52)	(17)	-	-	(69)
Net proved reserves at December 31, 2024	-	628	249	-	-	877
Revisions of previous estimates	-	(171)	-	-	-	(171)
Acquisitions	-	-	-	1,951	11	1,962
Divestitures	-	-	(235)	-	-	(235)
Production	-	(36)	(14)	(27)	(4)	(81)
Net proved reserves at December 31, 2025	-	421	-	1,924	7	2,352
Oil and Condensate (MBbl)						
Net proved reserves at December 31, 2023	-	194	147	-	-	341
Revisions of previous estimates	-	243	(20)	-	-	223
Acquisitions	-	1,175	-	-	17	1,192
Production	-	(173)	(11)	-	-	(184)
Net proved reserves at December 31, 2024	-	1,439	116	-	17	1,572
Revisions of previous estimates	-	(211)	-	-	(5)	(216)
Acquisitions	-	-	-	8,200	33	8,233
Divestitures	-	-	(107)	-	-	(107)
Production	-	(149)	(9)	(50)	(15)	(223)
Net proved reserves at December 31, 2025	-	1,079	-	8,150	30	9,259
Total Company (MMcfe)						
Net proved reserves at December 31, 2023	61,760	2,341	6,161	-	-	70,262
Revisions of previous estimates (1)(2)(3)	8,334	2,294	(606)	-	-	10,022
Acquisitions	-	11,371	-	-	102	11,473
Production	(5,700)	(1,555)	(405)	-	-	(7,660)
Net proved reserves at December 31, 2024	64,394	14,451	5,150	-	102	84,097
Revisions of previous estimates (4)(5)	13,100	(2,591)	-	-	(30)	10,479
Acquisitions	-	-	-	77,680	421	78,101
Divestitures	-	-	(4,812)	-	-	(4,812)
Production	(9,402)	(1,271)	(338)	(651)	(166)	(11,828)
Net proved reserves at December 31, 2025	68,092	10,589	-	77,029	327	156,037

(1) Revisions of previous estimates for Pennsylvania for 2024 include additions of 10,244 MMcf related to changes in previously adopted development plans, reductions of 2,849 MMcf related to commodity pricing, and additions of 939 MMcf related to technical revisions.

(2) Revisions of previous estimates for the Permian Basin for 2024 include additions of 2,317 MMcfe related to technical revisions and reductions of 23 MMcfe related to commodity pricing.

(3) Revisions of previous estimates for Oklahoma for 2024 include reductions of 196 MMcfe related to commodity pricing and 410 MMcfe related to technical revisions.

(4) Revisions of previous estimates for Pennsylvania for 2025 include reductions of 5,015 MMcf related to changes in previously adopted development plans, additions of 9,617 MMcf related to commodity pricing, and additions of 8,498 MMcf related to technical revisions.

(5) Revisions of previous estimates for the Permian Basin for 2025 include reductions of 1,326 MMcfe related to changes in previously adopted development plans, reductions of 429 MMcfe related to commodity pricing, and reductions of 836 MMcf related to technical revisions.

	Pennsylvania	Permian Basin	Oklahoma	Wyoming	Canada	Total
Proved developed reserves:						
Natural Gas (MMcf)						
At December 31, 2023	45,135	481	1,939	-	-	47,555
At December 31, 2024	54,150	1,265	1,436	-	-	56,851
At December 31, 2025	62,597	1,171	-	11,976	105	75,849
Natural Gas Liquids (MBbl)						
At December 31, 2023	-	116	133	-	-	249
At December 31, 2024	-	375	115	-	-	490
At December 31, 2025	-	307	-	1,285	7	1,599
Oil and condensate (MBbl)						
At December 31, 2023	-	194	78	-	-	272
At December 31, 2024	-	779	51	-	17	847
At December 31, 2025	-	752	-	3,218	30	4,000
Total proved developed reserves (MMcfe)						
At December 31, 2023	45,135	2,341	3,205	-	-	50,681
At December 31, 2024	54,150	8,189	2,432	-	102	64,873
At December 31, 2025	62,597	7,524	-	38,996	327	109,444
Proved undeveloped reserves:						
Natural Gas (MMcf)						
At December 31, 2023	16,625	-	1,736	-	-	18,361
At December 31, 2024	10,244	785	1,521	-	-	12,550
At December 31, 2025	5,495	419	-	4,609	-	10,523
Natural Gas Liquids (MBbl)						
At December 31, 2023	-	-	134	-	-	134
At December 31, 2024	-	253	134	-	-	387
At December 31, 2025	-	114	-	639	-	753
Oil and condensate (MBbl)						
At December 31, 2023	-	-	69	-	-	69
At December 31, 2024	-	660	65	-	-	725
At December 31, 2025	-	327	-	4,932	-	5,259
Total proved undeveloped reserves (MMcfe)						
At December 31, 2023	16,625	-	2,957	-	-	19,582
At December 31, 2024	10,244	6,263	2,717	-	-	19,224
At December 31, 2025	5,495	3,065	-	38,033	-	46,593
Total proved reserves:						
Natural Gas (MMcf)						
At December 31, 2023	61,760	481	3,675	-	-	65,916
At December 31, 2024	64,394	2,050	2,957	-	-	69,401
At December 31, 2025	68,092	1,590	-	16,585	105	86,372
Natural Gas Liquids (MBbl)						
At December 31, 2023	-	116	267	-	-	383
At December 31, 2024	-	628	249	-	-	877
At December 31, 2025	-	421	-	1,924	7	2,352
Oil and condensate (MBbl)						
At December 31, 2023	-	194	147	-	-	341
At December 31, 2024	-	1,439	116	-	17	1,572
At December 31, 2025	-	1,079	-	8,150	30	9,259
Total proved reserves (MMcfe)						
At December 31, 2023	61,760	2,341	6,162	-	-	70,263
At December 31, 2024	64,394	14,452	5,149	-	102	84,097
At December 31, 2025	68,092	10,589	-	77,029	327	156,037

Capitalized Costs Relating to Natural Gas and Oil Producing Activities

The following table sets forth the capitalized costs relating to Epsilon's crude oil and natural gas production activities at December 31, 2025 and 2024:

	Year ended December 31, 2025	Year ended December 31, 2024
Proved properties	$ 233,334,212	$ 191,879,210
Unproved properties	79,307,169	28,364,186
Total Oil & Gas Properties	312,641,381	220,243,396
Accumulated depreciation, depletion, amortization and impairment	(131,636,141)	(123,281,395)
Net capitalized costs	$ 181,005,240	$ 96,962,001

Costs Incurred for Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The following table summarizes costs incurred and capitalized in oil and natural gas properties related to acquisition, exploration and development activities. Property acquisition costs are those costs incurred to lease property, including both undeveloped leasehold and the purchase of reserves in place. Exploration costs include costs of identifying areas that may warrant examination and examining specific areas that are considered to have prospects containing oil and natural gas reserves, including costs of drilling exploratory wells, geological and geophysical costs and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling, as well as the costs to develop the gathering system.

	Pennsylvania	Permian Basin	Oklahoma	Wyoming	Canada	Total
Oil and Natural Gas Activities:						
Total costs incurred for oil and natural gas activities as of December 31, 2025						
Unproved acquisition costs	$ 407,320	$ 6,596	$ —	$ 58,236,953	$ 4,912,775	$ 63,563,644
Proved acquisition costs	27,093	478,531	—	44,000,000	27,230	44,532,854
Proved development costs	1,697,314	3,328,017	54,504	1,363,640	2,790,053	9,233,528
Total costs incurred	$ 2,131,727	$ 3,813,144	$ 54,504	$ 103,600,593	$ 7,730,058	$ 117,330,026
Total costs incurred for oil and natural gas activities as of December 31, 2024						
Unproved acquisition costs	$ 499,820	$ 1,345,113	$ —	$ —	$ 1,014,380	$ 2,859,313
Proved acquisition costs	17,389	12,147,327	—	—	—	12,164,716
Proved development costs	4,782,274	12,193,104	68,651	—	1,876,953	18,920,982
Total costs incurred	$ 5,299,483	$ 25,685,544	$ 68,651	$ —	$ 2,891,333	$ 33,945,011

Results of Operations for Natural Gas and Oil Producing Activities

The following table sets forth results of operations for natural gas and oil producing activities for the years ended December 31, 2025 and 2024:

	Year ended December 31, 2025	Year ended December 31, 2024
Oil and gas producing activities:		
Gas sales	$ 29,121,446	$ 10,786,068
Oil and other liquid sales	15,782,375	15,212,644
Total revenues	44,903,821	25,998,712
Lease operating costs	(12,518,325)	(7,264,824)
Depreciation, depletion, amortization, accretion and impairment	(14,603,299)	(10,718,231)
Income tax expense	589,535	(1,629,093)
Results of operations from oil and gas producing activities	$ 18,371,732	$ 6,386,564

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves

The following information has been developed utilizing procedures prescribed by the Extractive Activities—Natural Oil and Gas (Topic 932) of the ASC and based on natural gas reserves and production volumes estimated by our independent petroleum consultants, DeGolyer and MacNaughton and Cawley Gillespie & Associates. The commodity prices estimated below were based on a 12-month average of first-day-of-the-month commodity prices for the years 2025 and 2024. The following information may be useful for certain comparative purposes, but should not be solely relied upon in evaluating Epsilon or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of Epsilon.

The future cash flows presented below are based on expense and cost rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax basis of the properties and related carryforwards. The resulting tax-effected future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable and possible reserves as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of Epsilon's gas reserves as of December 31, 2025 and 2024.

	Year ended December 31,	
	2025	**2024**
Standard measure of discounted net cash flows		
Future cash inflows	$ 870,588,365	$ 248,266,584
Future production costs	(403,654,558)	(109,070,217)
Future development costs[1]	(119,751,295)	(31,461,723)
Future income taxes[2]	(53,642,936)	(18,611,204)
Future net cash flows (undiscounted)	293,539,576	89,123,440
10% annual discount for estimated timing of cash flows	(137,392,539)	(38,466,846)
Standardized measure of discounted future net cash flows	$ 156,147,037	$ 50,656,595

(1) Costs associated with the abandonment of proved properties are included in future development costs.

(2) Future income taxes for 2025 and 2024 were estimated using a combined federal and state statutory tax rate of approximately 24.4%.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth the changes in the standardized measure of discounted future net cash flows for the years ended December 31, 2025 and 2024:

	Year ended December 31,	
	2025	**2024**
Future net cash flows	$ 50,656,595	$ 32,972,908
Changes in price and production costs	26,092,350	(3,339,422)
Net changes in future development costs	493,413	(26,549,734)
Revenue less production and other costs	(30,520,727)	(17,599,243)
Acquisition of reserves	109,248,947	40,846,884
Divestitures of reserves	(3,372,093)	—
Revisions of previous quantity estimates	18,421,546	6,014,458
Development costs incurred	8,496	14,319,839
Net change in income taxes	(18,373,921)	(3,647,700)
Accretion of discount	6,230,973	3,742,998
Timing differences and other technical revisions	(2,738,542)	3,895,607
Future net cash flows	$ 156,147,037	$ 50,656,595

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and our principal financial officer, evaluated, as of the end of the period covered by this Annual Report on Form 10-K, the design and effectiveness of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on that evaluation, our principal executive officer and principal financial officer have concluded that as of December 31, 2025, our disclosure controls and procedures were not effective at the reasonable assurance level due to the material weakness described below. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and our management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As disclosed in Note 4 "Business Combination" included in the notes to the consolidated financial statements contained herein, the Company completed the acquisition of Peak Exploration & Production LLC and Peak BLM Lease LLC (collectively, "Peak"), on November 14, 2025 in a business combination. As discussed in Securities and Exchange Commission ("SEC") staff guidance, a company may conclude it will exclude an acquired business from the assessment of internal control over financial reporting during the first year after completion of an acquisition. In light of the overlap between a company's disclosure controls and procedures and its internal control over financial reporting, the evaluation of disclosure controls and procedures may also exclude an assessment of the disclosure controls and procedures of the acquired entity that are subsumed in internal control over financial reporting. In consideration of the SEC staff guidance, we excluded Peak from our assessment of the effectiveness of disclosure controls and procedures as of December 31, 2025. Peak's total assets and total revenues excluded from our assessment represented approximately 52% and 8% of the Company's consolidated total assets and consolidated total revenues, respectively, as of and for the year ended December 31, 2025.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for Epsilon as such term is defined in the Exchange Act. Our internal control structure is designed to provide reasonable assurance that assets are safeguarded and that transactions are properly executed and recorded. The internal control structure includes, among other things, established policies and procedures, the selection and training of qualified personnel as well as management oversight.

With the participation of our management, we performed an evaluation of the effectiveness of our internal control over financial reporting based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "2013 Framework)." As disclosed above, the Company completed the Peak acquisition on November 14, 2025. The scope of management's assessment of internal controls over financial reporting excluded the internal controls of Peak which is in accordance with guidance issued by the SEC Staff. Based upon our evaluation under the 2013 Framework, we have concluded that as of December 31, 2025 our internal control over financial reporting was not effective due to the material weakness discussed below.

Material Weakness in Internal Control over Financial Reporting

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

As part of our assessment of internal controls over financial reporting, management identified a material weakness related to the accounting for significant and non-standard transactions. After giving consideration to the material weakness, and the additional analyses and other procedures we performed to ensure that our Financial Statements included in this Annual Report on Form 10-K were prepared in accordance with GAAP, our management has concluded that our Financial

Statements present fairly, in all material respects, our financial position, results of operations and cash flows for the periods disclosed in conformity with GAAP.

Plan for Remediation of Material Weakness

We have initiated remediation efforts designed to strengthen review and approval procedures for significant and non-standard transactions. These remediation activities are ongoing. Until such measures are fully implemented and operating effectively for a sufficient period, we cannot conclude that our disclosure controls and procedures are effective.

Attestation Report of Independent Registered Public Accounting Firm

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by Epsilon's independent registered public accounting firm pursuant to rules of the SEC that permit Epsilon to provide only management's report in this Annual Report. We were not required to have, nor have we, engaged our independent registered public accounting firm to perform an audit of internal control over financial reporting pursuant to the rules of the Commission that permit us to provide only management's report in this Annual Report.

Changes in Internal Control Over Financial Reporting

As discussed above, on November 14, 2025, we completed the Peak acquisition. We are currently integrating the business and operations of Peak into our internal control over financial reporting. In executing the integration, we are evaluating changes to controls and procedures related to Peak's business and operations. We have excluded the Peak acquisition from our assessment of internal control over financial reporting.

Except as described above and the material weakness identified, there have been no significant changes in the Company's internal control over financial reporting during the quarter ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

During the quarter ended December 31, 2025, none of our directors or officers (as defined in Rule 16a-1(f) of the Exchange Act) adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The names, ages, business experience (for at least the past five years) and positions of our directors and executive officers as of December 31, 2025, are set out below. Our Board of Directors consisted of six members at such date. All directors serve until the next annual meeting of shareholders or until their successors are elected or appointed and qualified. The Board of Directors appoints the executive officers annually.

Directors and Executive Officers	Age	Position with us
Jason Stabell	51	Chief Executive Officer and Director
Henry N. Clanton	63	Chief Operating Officer
Andrew Williamson	37	Chief Financial Officer
John Lovoi	65	Chairman of the Board and Director
Tracy Stephens	65	Director
Jason Stankowski	55	Director
David Winn	63	Director
Nicola Maddox	70	Director
Jack Vaughn	80	Director
Bryan Lawrence	83	Director

Biographies of Corporate Directors and Executive Officers.

Jason Stabell. Mr. Stabell has served as chief executive officer and a director for Epsilon Energy Ltd. since July 2022. He has worked in the energy industry since 1998 with a focus on upstream E&P. Previously he served as President and CEO of Merlon International, LLC, a privately held company with assets in the Western Desert of Egypt and US Gulf Coast which was sold in 2019 to a publicly listed UK company where he served as an advisor until 2021. Previous to that, he served as CFO and ultimately President of privately held Merlon Petroleum Company, which had assets in the US Gulf Coast and Egypt and was sold in 2006. He has a BA in Economics from Williams College. We believe that Mr. Stabell is qualified to serve as a member of our board of directors as a result of his experience in the natural gas and oil industry.

Henry N. Clanton. Mr. Clanton has served as our chief operating officer since January 2017. He has over 30 years of experience in the upstream E&P sector. His experience includes financial and technical management over all phases of drilling, completions, production, and field operations. Before joining us, he spent 14 years with a private E&P start-up, ARES Energy, Ltd, which he co-founded and served as a Managing Partner. Previous to that time Mr. Clanton worked with Schlumberger, ARCO Permian, and Coastal Management Company. He holds a MBA and a BS in Petroleum Engineering from Texas A&M University.

Andrew Williamson. Mr. Williamson has served as our chief financial officer since July 2022. He has spent his entire career in the energy business. From 2012 to early 2019, he served as Corporate Development Manager then Vice President Finance (CFO) of Merlon International, LLC. More recently, he served as the Corporate Strategy Manager for Petrosantander Inc. Mr. Williamson started his career in management consulting advising energy clients on transaction due diligence, growth strategy, and cost reduction. He has a BBA in Finance and a BA in Political Science from Southern Methodist University.

John Lovoi. Mr. Lovoi has been chairman of our board of directors since July 2013. Mr. Lovoi has been the managing partner of JVL Advisors, LLC, a private natural gas and oil investment advisor, since November 2002. He is a Director of Helix Energy Solutions Group, an operator of offshore natural gas and oil properties and production facilities, the Chairman of Innovex International, a leading provider of a broad range of products and services to the global oil and gas industry. We believe that Mr. Lovoi is qualified to serve as a member of our board of directors as a result of his background in investment banking, equity research, and asset management, with an emphasis on the global natural gas and oil practice.

Tracy Stephens. Mr. Stephens has been a director since May 2018. He has also been a member of our Compensation, Nominating and Corporate Governance Committee, and Conflicts Committee since February 2019. He is the founder of Westminster Advisors, a CEO advisory services company, and served as its Chief Executive Officer from

January 2018. He was previously employed by Resources Global Professionals, a large business consulting company, from July 2001 to December 2016, and was the Chief Operating Officer the last three years. We believe that Mr. Stephens is qualified to serve as a member of our board of directors as a result of his extensive experience with public companies.

Jason Stankowski. Mr. Stankowski has been a director and member of the Audit Committee since January 2021. Mr. Stankowski is the founder and a partner and portfolio manager for Clayton Partners, LLC. He began his career at Prudential Securities in San Francisco and spent eight years in structured finance at CMA Capital Management, where he acted in a number of roles, including specializing in corporate retirement planning, structuring complex investment and financing structures for Fortune 1000 companies. He became designated as a Chartered Financial Analyst in 2003. We believe that Mr. Stankowski is qualified to serve as a member of our board of directors based on his corporate finance and experience in public equity markets.

David Winn. Mr. Winn has been a director and member of the Audit Committee since January 2021. Mr. Winn recently retired from a 36 year career in public accounting that involved extensive board interaction. From 2003 until July 2020, Mr. Winn was an Audit Partner for Grant Thornton LLP, which is an independent audit, tax, and advisory firm and the U.S. member firm of Grant Thornton International Ltd. During his tenure, Mr. Winn served as audit department head, industry program leader, an engagement partner, quality control reviewer, and was a relationship partner to large clients. Mr. Winn has extensive Securities and Exchange Commission reporting experience with registration statements and annual and quarterly filings. Previously Mr. Winn served as a Director for PricewaterhouseCoopers LLP and previously as a Partner with Arthur Andersen LLP. We believe that Mr. Winn is qualified to serve as a member of our board of directors because of his experience in public accounting and public company reporting.

Nicola Maddox. Ms. Maddox has over forty years' experience in the oil and gas industry. After receiving her BA in Communications, she was employed by Exxon Minerals starting as an Associate Landman eventually ending in Executive Management positions starting in 1993. She was a co-founder of Centurion Exploration Company in 2004, initially serving as an EVP and then becoming its President, CEO and Chairman of the Board from 2007 to 2009. At Merlon International, LLC, Ms. Maddox was SVP in charge of its Texas subsidiary. She advanced to EVP and ultimately President after Merlon sold its Egyptian subsidiary in 2019. Since 2022, she has been a self-employed energy advisor specializing in contract analysis, strategic planning, and negotiation strategies. We believe that Ms. Maddox is qualified to serve as a member of our board of directors because of his significant industry experience in upstream oil and gas.

Jack E. Vaughn. Mr. Vaughn is the founder of Peak E&P and has served as the Chairman of the board of directors and the Chief Executive Officer of Peak E&P since its formation in March 2011. Mr. Vaughn has almost 50 years of experience in the exploration and production industry. From 2002 to 2011, Mr. Vaughn was the Chairman of the board of directors and Chief Executive Officer for three prior iterations of Peak E&P with projects in the Granite Wash in the Texas Panhandle, the Barnett Shale in the Ft. Worth Basin, and in the Bakken Formation in the Williston Basin of North Dakota. Prior to forming Peak E&P, Mr. Vaughn served as the Vice President–Rocky Mountain Division for EnerVest Management Partners Ltd. from 1996 to 2002. Mr. Vaughn also managed a successful San Juan Basin coal bed methane project owned by an EnerVest Management Partners Ltd. and GE Capital Oil & Gas partnership and later sold to Texaco Inc. in November 2001. Before that, Mr. Vaughn was an Executive Project Manager for the Hillman Company Energy Group, where he managed the development of a successful CBM project in the San Juan Basin from 1989 to 2002. Prior to that time, Mr. Vaughn worked as a consultant in drilling and completion operations and project management throughout the Rockies, East Texas, and the Mid-Continent for a number of independents. Mr. Vaughn started his career in 1968 with Amoco Oil Company. Mr. Vaughn also served as member of the board of directors for Bonanza Creek Energy, Inc., the predecessor of Civitas Resources, Inc., from April 2017 until its acquisition by Civitas in April 2021. Mr. Vaughn holds a B.S. in Petroleum Engineering from the University of Texas at Austin.

Bryan H. Lawrence. Mr. Lawrence is the founder and managing member Yorktown Energy Partners, which for over 25 years has managed private equity partnerships that have made investments in companies engaged in the energy industry. Mr. Lawrence was employed with the investment firm of Dillon, Read & Co. Inc. ("*Dillon Read*") from 1966 to 1997, serving most recently as a Managing Director until Dillon Read merged with SCB Warburg in September 1997. Mr. Lawrence also serves as a director of the following publicly traded companies: Ramaco Resources, Inc., Riley Exploration Permian, Inc., Hallador Energy Company and Kestrel Heat LLC, the general partner of Star Group, L.P., as well as other non-public companies in the energy industry in which Yorktown holds equity interests. Mr. Lawrence is a graduate of Hamilton College and holds an M.B.A. from Columbia University.

Corporate Governance Practices and Policies

Our corporate governance practices and policies are administered by the board of directors and by committees of the board appointed to oversee specific aspects of our management and operations, pursuant to written charters and policies adopted by the Board and such committees.

The Board of Directors

The Board is committed to a high standard of corporate governance practices. The Board believes that this commitment is not only in the best interests of the shareholders but that it also promotes effective decision-making at the Board level. The Board is of the view that its approach to corporate governance is appropriate and complies with the objectives and guidelines relating to corporate governance set out in National Instrument 58-201 adopted by the Canadian securities administrators, or NI 58-201, as well as the governance requirements of the NASDAQ Global Market. In addition, the Board monitors and considers for implementation the corporate governance standards that are proposed by various Canadian regulatory authorities or that are published by various non-regulatory organizations in Canada. The Board has also established a Compensation, Nominating and Corporate Governance Committee and has adopted a Compensation, Nominating and Corporate Governance Charter to ensure the objectives of NI 58-201 and the NASDAQ Global Market are met.

Mr. Lovoi is the Managing Partner of JVL Advisors, LLC, beneficial owner of 1.29% of our common shares and Chairman of the Board.

The Board held eleven meetings during 2025 and ten meetings during 2024. All Board meetings were conducted with open and candid discussions. As such, directors did not hold any separate meetings, other than Audit and Compensation, Nominating and Corporate Governance Committee meetings. The members of the Board have the ability to meet on their own and are authorized to retain independent financial, legal and other experts as required whenever, in their opinion, matters come before the Board that require an independent analysis by the members of the Board. The Board intends to hold at least four regular meetings each year, as well as additional meetings as required. The Board has not established any required attendance levels for the Board and committee meetings. In setting the regular meeting schedule, care is taken to ensure that meeting dates are set to accommodate directors' schedules so as to encourage full attendance.

The Board has stewardship responsibilities, including responsibilities with respect to oversight of our investments, management of the Board, monitoring of our financial performance, financial reporting, financial risk management and oversight of policies and procedures, communications and reporting and compliance. In carrying out its mandate, the Board meets regularly and a broad range of matters are discussed and reviewed for approval. These matters include overall plans and strategies, budgets, internal controls and management information systems, risk management as well as interim and annual financial and operating results. The Board is also responsible for the approval of all major transactions, including property acquisitions, property divestitures, equity issuances and debt transactions, if any. The Board strives to ensure that our corporate actions correspond closely with the objectives of its shareholders. The Board will meet at least once annually to review in depth our strategic plan and review our available resources required to carry out our growth strategy and to achieve its objectives. The mandate of the Board is to be reviewed by the Board annually.

Position Descriptions. The Board has outlined the responsibilities in respect to our Chief Executive Officer, or CEO. The Board and CEO do not have a written position description for the CEO; however, the CEO's principal duties and responsibilities are planning our strategic direction, providing leadership, acting as our spokesperson, reporting to shareholders, and overseeing our executive management with respect to operations and finance.

The charter for each of the Board committees outlines the duties and responsibilities of the members of each of the committees, including the chair of such committees. See ''Board Committees'' below.

Orientation and Continuing Education. We have not adopted a formalized process of orientation for new Board members. However, all directors have been provided with a base line of knowledge about us that serves as a basis for informed decision making. This includes a combination of written material, in person meetings with our senior management, site visits and other briefings and training, as appropriate.

Directors are kept informed as to matters affecting, or that may affect, our operations through reports and presentations at the quarterly Board meetings. Special presentations on specific business operations are also provided to the Board.

Ethical Business Conduct and Whistleblower Policy. Our Code of Ethics and Whistleblower Policy are available on our website at http://www.epsilonenergyltd.com/. Each director is expected to disclose all actual or potential conflicts of interest and refrain from voting on matters in which such director has a conflict of interest. In addition, a director must recuse himself from any discussion or decision on any matter of which the director is precluded from voting as a result of a conflict of interest. The Board has reviewed and approved a disclosure and insider trading policy for us, in order to promote consistent disclosure practices aimed at informative, timely and broadly disseminated disclosure of material information to the market in accordance with applicable securities legislation. The disclosure policy promotes, among other things, the disclosure and reporting of any serious weaknesses which may affect the financial stability and assets of us and our operating entities.

National Instrument 52-110 adopted by the Canadian securities administrators, the listing standards of the Toronto Stock Exchange and the listing standards of the NASDAQ Global Market require the Audit Committee to establish formal procedures for (a) the receipt, retention, and treatment of complaints received by us and our subsidiaries regarding accounting, internal accounting controls, or auditing matters and (b) the confidential, anonymous submission by our consultants or employees of concerns regarding questionable accounting or auditing matters. We are committed to achieving compliance with all applicable securities laws and regulations, accounting standards, accounting controls and audit practices. In addition, we post on our website all disclosures that are required by law or the listing standards of the NASDAQ Global Market concerning any amendments to, or waivers from, any provision of the code.

Assessments. The Board does not conduct regular assessments of the Board, its committees or individual directors, however, the Board does periodically review and satisfy itself at meetings that the Board, its committees and its individual directors are performing effectively.

Board Diversity. Our Compensation, Nominating and Corporate Governance Committee is responsible for reviewing with the board of directors, on an annual basis, the appropriate characteristics, skills and experience required for the board of directors as a whole and its individual members. In evaluating the suitability of individual candidates (both new candidates and current members), the nominating and corporate governance committee, in recommending candidates for election, and the board of directors, in approving (and, in the case of vacancies, appointing) such candidates, will take into account many factors, including the following:

- personal and professional integrity, ethics and values;
- experience in corporate management, such as serving as an officer or former officer of a publicly held company;
- experience as a board member or executive officer of another publicly held company;
- strong finance experience;
- diversity of expertise and experience in substantive matters pertaining to our business relative to other board members;
- diversity of background and perspective, including, but not limited to, with respect to age, gender, race, place of residence and specialized experience;
- experience relevant to our business industry and with relevant social policy concerns; and
- relevant academic expertise or other proficiency in an area of our business operations.

Currently, our Board evaluates each individual in the context of the board of directors as a whole, with the objective of assembling a group that can best maximize the success of the business and represent stockholder interests through the exercise of sound judgment using its diversity of experience in these various areas.

Board Committees

The Board has two committees. The committees are the Audit Committee and the Compensation, Nominating and Corporate Governance Committee. Each committee has been constituted with independent directors.

Audit Committee. The Audit Committee currently consists of David Winn (Chairman), John Lovoi, and Jason Stankowski. All members of the Audit Committee are independent and financially literate under the applicable rules and regulations of the SEC and the NASDAQ Global Market.

The Audit Committee meets at least on a quarterly basis to review and approve our consolidated financial statements before the financial statements are publicly filed.

The Audit Committee reviews our interim unaudited condensed consolidated financial statements and annual audited consolidated financial statements and certain corporate disclosure documents including the Annual Information Form, Management's Discussion and Analysis, and annual and interim earnings press releases before they are approved by the Board. The Audit Committee reviews and makes a recommendation to the Board in respect of the appointment and compensation of the external auditors and it monitors accounting, financial reporting, control and audit functions. The Audit Committee meets to discuss and review the audit plans of external auditors and is directly responsible for overseeing the work of the external auditors with respect to preparing or issuing the auditors' report or the performance of other audit, review or attest services, including the resolution of disagreements between management and the external auditors regarding financial reporting. The Audit Committee questions the external auditors independently of management and reviews a written statement of its independence. The Audit Committee must be satisfied that adequate procedures are in place for the review of our public disclosure of financial information extracted or derived from our consolidated financial statements and it periodically assesses the adequacy of those procedures. The Audit Committee must approve or pre-approve, as applicable, any non-audit services to be provided to us by the external auditors. In addition, it reviews and reports to the Board on our risk management policies and procedures and reviews the internal control procedures to determine their effectiveness and to ensure compliance with our policies and avoidance of conflicts of interest. The Audit Committee has established procedures for dealing with complaints or confidential submissions which come to its attention with respect to accounting, internal accounting controls or auditing matters. To date, neither the Board nor the Audit Committee has formally assessed any individual director with respect to their effectiveness and contribution to us in their capacity as a director. Instead, members of the Board have relied on informal conversations among themselves to adequately cover such matters.

The Audit Committee operates under a written charter that satisfies the applicable standards of the SEC and The NASDAQ Global Market. A copy of the Audit Committee Charter can be found on our website at www.epsilonenergyltd.com.

Compensation, Nominating and Corporate Governance Committee. The Compensation, Nominating and Corporate Governance Committee is currently comprised of Tracy Stephens (Chairman), John Lovoi, Nicola Maddox, Bryan Lawrence, and Jack Vaughn. All members of this committee, with the exception of Bryan Lawrence and Jack Vaughn, are independent directors.

The Compensation, Nominating and Corporate Governance Committee's mandate is to:

1. Assist and advise the Board regarding its responsibility for oversight of our compensation policy; provided that all determinations on officer compensation will be subject to review and approval by the Board;
2. Study and evaluate appropriate compensation mechanisms and criteria;
3. Develop and establish appropriate compensation policies and practices for the Board and our senior management, including our security-based compensation arrangements;
4. Evaluate senior management;
5. Serve in an advisory capacity on organizational and personnel matters to the Board;
6. Assist the Board by identifying individuals qualified to serve on the Board and its committees;
7. Recommend to the Board the director nominees for the next annual meeting;
8. Recommend to the Board members and chairpersons for each committee;
9. Develop and recommend to the Board and review from time to time, a set of corporate governance principles and monitor compliance with such principles; and
10. Serve in an advisory capacity on matters of governance structure and the conduct of the Board.

These responsibilities include reporting and making recommendations to the Board for their consideration and approval. Corporate governance also relates to the activities of the Board, the members of which are elected by and are accountable to the shareholders, and takes into account the role of the individual members of management who are appointed by the Board and who are charged with the day-to-day management of us. The Board is committed to sound corporate governance practices, which are both in the interest of its shareholders and contribute to effective and efficient decision making.

The Compensation, Nominating and Corporate Governance Committee operates under a written charter that satisfies the applicable standards of the SEC and The NASDAQ Global Market. A copy of such charter can be found on our website at www.epsilonenergyltd.com.

Communications to the Board

Shareholders may communicate directly with our Board or any director by writing to the Board or a director in care of the corporate secretary at Epsilon Energy Ltd., 500 Dallas Street, Suite 1250, Houston, Texas 77002, or by faxing their written communication to AeRayna Flores at (281) 668-0985. Shareholders may also communicate with the Board or any director by calling Ms. Flores at (281) 670-0002. Ms. Flores will review any communication before forwarding it to the Board or director, as the case may be.

Employment Agreements

All named executive officers have executed employment contracts with us. Mr. Jason Stabell's employment agreement is effective from July 1, 2022 and filed in Form 8-K with the SEC on June 24, 2022. Mr. Henry Clanton's employment agreement is effective from January 1, 2024 and filed in Form 8K with the SEC on March 12, 2024. Mr. Andrew Williamson's employment agreement is effective from July 1, 2022 and filed in Form 8-K with the SEC on June 24, 2022.

ITEM 11. EXECUTIVE COMPENSATION.

Summary Compensation Table

The Board adopted the 2020 Equity Incentive Plan (the "2020 Plan") on July 22, 2020 subject to approval by Epsilon's shareholders at Epsilon's 2020 Annual General and Special Meeting of shareholders, which occurred on September 1, 2020 (the "Meeting"). Shareholders approved the 2020 Plan at the Meeting.

The following table sets out information concerning the compensation paid to our principal executive officer and our two most highly compensated executive officers other than our principal executive officer, or our named executive officers, for the two years ended December 31, 2025 and 2024. Compensation amounts in the following table are in U.S. dollars.

Name and principal position	Year	Salary	Bonuses	Share-based Awards	Other Compensation (4)	Total Compensation
Jason Stabell, CEO (1)	2025	$ 331,000	$ 237,000	$ 796,998	$ 16,760	$ 1,381,758
	2024	$ 322,000	$ 164,000	$ 552,001	$ 18,446	$ 1,056,447
Henry N. Clanton, COO (2)	2025	$ 290,000	$ 178,000	$ 237,002	$ 15,042	$ 720,044
	2024	$ 282,000	$ 123,000	$ 164,000	$ 19,341	$ 588,341
Andrew Williamson, CFO (3)	2025	$ 271,000	$ 214,000	$ 340,001	$ 14,058	$ 839,059
	2024	$ 264,000	$ 139,000	$ 221,001	$ 17,469	$ 641,470

(1) Mr. Stabell was hired as our chief executive officer in July 2022. His 2025 base salary was $331,000.

2025—Share award of 166,736 common shares valued at $4.78 per share, the 30-day volume weighted average price ending on the grant date of December 31, 2025, which vests evenly over a three year period.

Share award of 20,007 dividend equivalent rights common shares valued at $4.64 per share, market price on the grant date of December 31, 2025, which vested immediately.

2024—Share award of 88,889 common shares valued at $6.21 per share, market price on the grant date of December 31, 2024, which vests evenly over a three year period.

(2) Mr. Henry Clanton was hired as our chief operating officer in January 2018. His 2025 base salary was $290,000.

2025—Share award of 49,582 common shares valued at $4.78 per share, the 30-day volume weighted average price ending on the grant date of December 31, 2025, which vests evenly over a three year period.
Share award of 2,946 dividend equivalent rights common shares valued at $4.64 per share, market price on the grant date of December 31, 2025, which vested immediately.

2024—Share award of 26,409 common shares valued at $6.21 per share, market price on the grant date of December 31, 2024, which vest evenly over a three year period.

(3) Mr. Andrew Williamson was hired as our chief financial officer in July 2022. His 2025 base salary was $271,000.

2025—Share award of 71,130 common shares valued at $4.78 per share, the 30-day volume weighted average price ending on the grant date of December 31, 2025, which vests evenly over a three year period.
Share award of 8,315 dividend equivalent rights common shares valued at $4.64 per share, market price on the grant date of December 31, 2025, which vested immediately.

2024—Share award of 35,588 valued at $6.21 per share, market price on the grant date of December 31, 2024, which grants vest evenly over a three year period.

(4) As a Company policy, Epsilon matches on 401K contributions up to 5%.

Mr. Stabell and the Company entered into an Executive Employment Agreement, effective July 1, 2022. The terms of the Employment Agreement have been adjusted by the Board subsequent to its effective date. Mr. Stabell serves as CEO on an "at-will" basis for an annual base salary of $331,000 during 2025 and $322,000 during 2024. In addition to his base salary, Mr. Stabell is eligible to receive an annual incentive cash bonus targeted at $200,000 for achieving performance goals established by the Compensation Committee of the Board in its sole discretion for the then current calendar year. Additionally, Mr. Stabell is eligible for equity awards in the discretion of the Compensation Committee, which in 2025 included 166,736 common shares $4.78 per share (the 30-day volume weighted average price ending on the grant date of December 31, 2025) which vests evenly over a three year period, and in 2024 included 88,889 common shares valued at $6.21 per share (market price on the grant date of December 31, 2024), which vests evenly over a three year period. Mr. Stabell is entitled to participate in all applicable Company benefit plans, programs, or arrangements that the Company may offer to its executives generally, from time to time, and as may be amended from time to time.

Mr. Clanton and the Company entered into an Executive Employment Agreement, effective January 14, 2024. The terms of the Employment Agreement have been adjusted by the Board subsequent to its effective date. Mr. Clanton serves as COO on an "at-will" basis for an annual base salary of $290,000 during 2025 and $282,000 during 2024. In addition to his base salary, Mr. Clanton is eligible to receive an annual incentive cash bonus targeted at $150,000 for achieving performance goals established by the Compensation Committee of the Board in its sole discretion for the then current calendar year. Additionally, Mr. Clanton is eligible for equity awards in the discretion of the Compensation Committee, which in 2025 included 49,582 common shares valued at $4.78 per share (the 30-day volume weighted average price ending on the grant date of December 31, 2025), which vests evenly over a three year period and in 2024 included 26,409 common shares valued at $6.21 per share (market price on the grant date of December 31, 2024), which vests evenly over a three year period. Mr. Clanton is entitled to participate in all applicable Company benefit plans, programs, or arrangements that the Company may offer to its executives generally, from time to time, and as may be amended from time to time.

Mr. Williamson and the Company entered into an Executive Employment Agreement, effective July 1, 2022. The terms of the Employment Agreement have been adjusted by the Board subsequent to its effective date. Mr. Williamson serves as CFO on an "at-will" basis for an annual base salary of $271,000 during 2025 and $264,000 during 2024. In addition to his base salary, Mr. Williamson is eligible to receive an annual incentive cash bonus targeted at $170,000 for achieving performance goals established by the Compensation Committee of the Board in its sole discretion for the then current calendar year. Additionally, Mr. Williamson is eligible for equity awards in the discretion of the Compensation Committee, which in 2025 included 71,130 common shares valued at $4.78 per share (the 30-day volume weighted average price ending on the grant date of December 31, 2025), which vests evenly over a three year period and in 2024 included 35,588 common shares valued at $6.21 per share (market price on the grant date of December 31, 2024), which vests evenly over a three year period. Mr. Williamson is entitled to participate in all applicable Company benefit plans, programs, or arrangements that the Company may offer to its executives generally, from time to time, and as may be amended from time to time.

Description of the 2020 Equity Incentive Plan

The 2020 Plan was approved by the Board on July 22, 2020 and shareholders on September 1, 2020 as a replacement of our Amended and Restated 2017 Stock Option Plan and the Share Compensation Plan.

The 2020 Plan is administered by the Board, a committee of the Board or one or more officers delegated authority by the Board to administer the 2020 Plan. The Board has the authority in its discretion to interpret the 2020 Plan. The Board determines to whom stock options, stock appreciation rights, restricted stock and stock units, performance shares and units, other stock-based awards and cash-based awards are granted, subject to options and all other terms and conditions of the awards.

The maximum number common shares that may be issued under the 2020 Plan is 2,000,000. As of December 31, 2025, 234,834 performance stock units ("PSUs"), and 1,624,529 time-based restricted shares have been issued, leaving 140,637 shares available to be granted under the 2020 Plan.

If the shares granted under the 2020 Plan expire or terminate for any reason without having been issued or are forfeited, they again become available for grant under the 2020 Plan. Shares granted under the 2020 Plan are not transferable or assignable other than by will or other testamentary instrument or the laws of succession.

In the event we undergo a change of control by a reorganization, acquisition, amalgamation or merger (or a plan or arrangement in connection with any of these) with respect to which all or substantially all of the persons who were the beneficial owners of the common shares immediately prior to such transaction do not, following such transaction, beneficially own, directly or indirectly more than 50% of the resulting voting power, a sale of all, or substantially all, of the Company's assets, or the liquidation, dissolution or winding-up of the Company, outstanding awards shall be subject to the definitive agreement entered into by the Company in connection with the change of control.

At December 31, 2025, we were authorized to issue equity securities as follows:

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans (excluding shares in column (a))
Common shares under 2020 Equity Incentive Plan	781,792	$ 5.15	140,637

Incentive Plan Awards for Named Executive Officers

Outstanding Share Based Awards as of December 31, 2025 are as follows:

	Share-based Awards	
Name	Number of Shares or Units of Shares that Have Not Vested	Market Value of Share-Based Awards that Have Not Vested
Jason Stabell	293,067	$ 1,359,831
Henry N. Clanton	73,226	$ 339,769
Andrew Williamson	122,829	$ 569,927

Incentive Plan Awards—Value Vested or Earned for Named Executive Officers

The values of incentive plan awards that were vested or earned during the year ended December 31, 2025 are as follows:

Name	Share-based awards—Value Vested During the Year
Jason Stabell	$ 710,515
Henry N. Clanton	$ 129,683
Andrew Williamson	$ 293,095

We have adopted the 2020 Plan as an incentive-based share award plan applicable to all named executive officers and employees.

Change of control is defined as any event whereby any person acquires at least 50% of the Company's stock or if a group of shareholders causes at least 50% of the board members to change.

DIRECTOR COMPENSATION

The following table contains compensation earned in the year ended December 31, 2025 by our independent directors who are not named executive officers:

Name	Fees Earned	Share-Based Awards	Total
John Lovoi	$ 95,000	$ 65,000	$ 160,000
Tracy Stephens	$ 65,000	$ 65,000	$ 130,000
David Winn	$ 70,000	$ 65,000	$ 135,000
Jason Stankowski	$ 55,000	$ 65,000	$ 120,000
Nicola Maddox	$ 55,000	$ 65,000	$ 120,000

On a quarterly basis, we compensate each director for services rendered (unless a director elects not to receive payment) and reimburse reasonable out-of-pocket travel expenses when incurred. At this time, Bryan Lawrence does not receive any compensation and Jack Vaughn will not receive compensation until his one year severance payment is completed in November 2026

As of January 1, 2023, board member compensation is fixed at an annual fee of $55,000 paid in cash quarterly and $65,000 as a share-based award valued at the prior year-end share price (vesting evenly over a three year period). The chairman of the board receives an additional $40,000 annual cash fee, the chairman of the audit committee receives an additional $15,000 annual cash fee, and the chairman of the compensation, nominating, and corporate governance committee receives an additional $10,000 annual cash fee.

Incentive Plan Awards—Value Vested or Earned During the Year for Directors (Other Than Named Executive Officers)

Outstanding Share-Based Awards and Option-Based Awards as of December 31, 2025 are as follows:

	Share-based Awards	
Name	**Number of Shares or Units of Shares that Have Not Vested**	**Market or Payout Value of Share-Based Awards that Have Not Vested**
John Lovoi	24,842	$ 115,267
Tracy Stephens	24,842	$ 115,267
David Winn	24,842	$ 115,267
Jason Stankowski	24,842	$ 115,267
Nicola Maddox	24,841	$ 115,262

The values of incentive plan awards that were vested or earned during the year ended December 31, 2025 are as follows:

Name	**Share-based awards Value Vested During the Year**
John Lovoi	$ 119,773
Tracy Stephens	$ 72,749
David Winn	$ 72,749
Jason Stankowski	$ 72,749
Nicola Maddox	$ 63,309

Directors and Officers Liability Insurance

We maintain directors' and officers' liability insurance for the protection of our directors and officers against liability incurred by them in their capacities as our directors and officers. The policy provides an aggregate limit of liability of $35,000,000 with a retention held by the Company of $1,500,000. The current annual premium for the Directors' and Officers' liability insurance is approximately $350,000 and is re-bid annually. The premium is not allocated between Directors and Officers as separate groups.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The table set forth below is information with respect to beneficial ownership of common shares as of March 19, 2025, by our named executive officers, by each of our directors, by all our current executive officers and directors as a group, and by each person known to us who beneficially own 5% or more of the outstanding common shares. To our knowledge, each person named in the table has sole voting and investment power with respect to the common shares identified as beneficially owned.

Unless otherwise indicated, the address of each of the individuals named below is c/o Epsilon Energy Ltd., 500 Dallas, Suite 1250, Houston, Texas 77002.

Name of Beneficial Owner	Number of Common Shares	Percentage of Common Shares Owned
5% Stockholders		
Yorktown Energy Partners[1]	6,617,272	21.88 %
Solas Capital Management LLC [2]	3,545,186	11.72 %
Named Executive Officers and Directors		
Jason Stabell [3]	815,809	*
Henry Clanton [4]	103,024	*
Andrew Williamson [5]	174,039	*
John Lovoi [6]	305,853	*
Tracy Stephens [7]	74,493	*
David Winn [8]	45,593	*
Jason Stankowski [9]	393,354	*
Nicola Maddox [10]	21,541	*
Bryan Lawrence [11]	6,617,272	21.88 %
Jack Vaughn [12]	29,886	*
All executive officers and directors as a group (10 persons)	8,580,864	28.38 %

* Indicates beneficial ownership of less than 5% of outstanding shares.

(1) The address of Yorktown Energy Partners is 410 Park Avenue, 20th Floor, New York, New York 10022. Pursuant to a Schedule 13D filed with the SEC on November 14, 2025, Yorktown XI Associates LLC may be deemed to have voting and dispositive power with respect to these common shares. This share total includes shares held by Yorktown Energy Partners IX, X and XI.

(2) The address of Solas Capital Management, LLC is 1063 Post Rd, 2nd Floor, Darien, Connecticut 06820. Pursuant to a Schedule 13G filed with the SEC on February 14, 2024, Solas Capital Management, LLC ("Solas") and Frederick Tucker Golden share voting and dispositive power with respect to these common shares. All of the securities reported are owned by advisory clients of Solas, none of which is a beneficial owner of more than 5% as of July 14, 2020.

(3) Mr. Stabell is our chief executive officer and a member of our board of directors.

(4) Mr. Clanton is our chief operating officer.

(5) Mr. Williamson is our chief financial officer.

(6) Mr. Lovoi is the chairman of our board of directors and is the managing member of JVL Advisors, LLC.

(7) Mr. Stephens is a member of our board of directors.

(8) Mr. Winn is a member of our board of directors.

(9) Mr. Stankowski is a member of our board of directors and a partner and portfolio manager for Clayton Partners, LLC.

(10) Ms. Maddox is a member of our board of directors.

(11) Mr. Lawrence is a member of our board of directors and is the founder and managing member Yorktown Energy Partners.

(12) Mr. Vaughn is a member of the board of directors.

Changes in Control. We do not know of any arrangement, the operation of which may at a subsequent date result in a change in control of us.

Securities Authorized For Issuance under Equity Compensation Plans

The information required by Item 201 of Regulation S-K in *"Item 1. Business – Market for Our Common Equity and Related Stockholder Matters."*

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Certain Relationships and Related Transactions

Since the beginning of fiscal 2025, there has not been, nor is there currently proposed, any transaction or series of similar transactions to which we were or are a party in which the amount involved exceeded or exceeds $120,000 and in which any of our directors, executive officers, holders of more than 5% of any class of our voting securities, or any member of the immediate family of any of the foregoing persons, had or will have a direct or indirect material interest, except for the compensation and other arrangements described in "Executive Compensation" and "Director Compensation" elsewhere in this document and the transactions described below.

Independence of the Board of Directors

The Board is currently composed of seven directors who provide us with a wide diversity of business experience.

Our Board has determined that John Lovoi, Tracy Stephens, Jason Stankowski, David Winn, and Nicola Maddox, are independent in accordance with the listing requirements of the NASDAQ Global Market, representing over 50% of the Board. Our Board conducted its independence analysis for each of its current members, considering all relevant facts and circumstances, including the director's other commercial, accounting, legal, banking, consulting, charitable and familial relationships. Pursuant to its review, the Board determined that with respect to each of its current members, there are no disqualifying factors with respect to director independence enumerated in the listing standards of NASDAQ or any relationships that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director, and that each such member is an "independent director" as defined in the listing standards of NASDAQ.

Indemnification of Officers and Directors

Under Section 124 of the Business Corporations Act (Alberta) (the "ABCA"), except in respect of an action by or on behalf of us or body corporate to procure a judgment in our favor, we may indemnify a current or former director or officer or a person who acts or acted at our request as a director or officer of a body corporate of which we are or were a shareholder or creditor and the heirs and legal representatives of any such persons (collectively, "Indemnified Persons") against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by any such Indemnified Person in respect of any civil, criminal or administrative actions or proceedings to which the director or officer is made a party by reason of being or having been our director or officer, if (i) the director or officer acted honestly and in good faith with a view to our best interests, and (ii) in the case of a criminal or administrative action or proceeding that is enforced by a monetary penalty, the director or officer had reasonable grounds for believing that such director's or officer's conduct was lawful (collectively, the "Indemnification Conditions").

Notwithstanding the foregoing, the ABCA provides that an Indemnified Person is entitled to indemnity from us in respect of all costs, charges and expenses reasonably incurred by the person in connection with the defense of any civil, criminal or administrative action or proceeding to which the person is made a party by reason of being or having been our director or officer, if the person seeking indemnity (i) was substantially successful on the merits in the person's defense of the action or proceeding, (ii) fulfills the Indemnification Conditions, and (iii) is fairly and reasonably entitled to indemnity. We may advance funds to an Indemnified Person for the costs, charges and expenses of a proceeding; however, the Indemnified Person shall repay the moneys if such individual does not fulfill the Indemnification Conditions. The indemnification may be made in connection with a derivative action only with court approval and only if the Indemnification Conditions are met.

As contemplated by Section 124(4) of the ABCA and our by-laws, we have acquired and maintain liability insurance for our directors and officers with coverage and terms that are customary for a company of our size in our industry of operations. The ABCA provides that we may not purchase insurance for the benefit of an Indemnified Person against a liability that relates to the person's failure to act honestly and in good faith with a view to our best interests.

Our by-laws provide that, subject to the ABCA, the Indemnified Persons shall be indemnified against all costs, charges and expenses, including an amount paid to settle an action or satisfy a judgment, reasonably incurred by such person in respect of any civil, criminal or administrative action or proceeding to which such person is made a party by reason of being or having been a director or officer of the Company or such body corporate, if the Indemnification Conditions are satisfied. In addition, pursuant to our by-laws, we may indemnify such person in such other circumstances as the ABCA or law permits.

Our by-laws also provide that none of our directors or officers shall be liable for the acts, receipts, neglects or defaults of any other director, officer or employee, or for joining in any receipt or other act for conformity, or for any loss, damage or expense happening to us through the insufficiency or deficiency of title to any property acquired for or on behalf of us, or for the insufficiency or deficiency of any security in or upon which any of our moneys shall be invested, or for any loss or damage arising from the bankruptcy, insolvency or tortious acts of any person with whom any of our moneys, securities or effects shall be deposited, or for any loss occasioned by any error of judgment or oversight on his part, or for any other loss, damage or misfortune which shall happen in the execution of the duties of his or her office or in relation thereto; provided that nothing in our by-laws shall relieve any director or officer from the duty to act in accordance with the ABCA and the regulations thereunder. The foregoing is premised on the requirement under our by-laws that each of our directors and officers in exercising his or her powers and discharging duties shall act honestly and in good faith with a view to our best interests and exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

We have entered into indemnification agreements with our directors and officers which generally require that we indemnify and hold the indemnitees harmless to the greatest extent permitted by law for liabilities arising out of the indemnitees' service to us and our subsidiaries as directors and officers, if the indemnitees acted honestly and in good faith with a view to our best interests and, with respect to criminal or administrative actions or proceedings that are enforced by monetary penalty, if the indemnitee had no reasonable grounds to believe that his or her conduct was unlawful. The indemnification agreements also provide for the advancement of defense expenses to the indemnitees by us.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The following table summarizes fees billed to us for fiscal 2025 and for fiscal 2024 by our principal auditors, BDO USA, P.C.:

	December 31, 2025	December 31, 2024
Audit Fees:		
Audit of financial statements	$ 535,262	$ 388,886
Total Audit Fees	$ 535,262	$ 388,886

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a)1. Financial Statements:
Report of Independent Registered Public Accounting Firm (PCAOB ID 243)
Consolidated Balance Sheets as of December 31, 2025 and December 31, 2024.
Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2025 and December 31, 2024.
Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2025 and December 31, 2024.
Consolidated Statements of Cash Flows for the years ended December 31, 2025 and December 31, 2024.
Notes to Consolidated Financial Statements

(a)2. Financial Statement Schedules:
None.

(a)3. Exhibits

3.1	Articles of Incorporation of Epsilon Energy Ltd (incorporated by reference to Exhibit 3.1 of Form 10, File No. 001-38770, filed on December 21, 2018).
3.2	Bylaws of Epsilon Energy Ltd. (incorporated by reference to Exhibit 3.2 of Form 10, File No. 001-38770, filed on December 21, 2018)
3.3	Articles of Amendment dated December 19, 2019 (incorporated by reference to Exhibit 3.3 of Form 10, File No. 001-38770, filed on December 21, 2018)
4.1	Description of Registrant's Securities Registered Under Section 12 of the Exchange Act. (incorporated by reference to Exhibit 4.1 of Form 10-K, File No. 001-38770, filed on March 18, 2020)
10.1+	Henry Clanton Employment Agreement (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 001-38770, filed on March 12, 2024)
10.2	Anchor Shipper Gas Gathering Agreement, effective January 1, 2024, by and between Appalachia Midstream Services, L.L.C. and Epsilon Energy USA, Inc., as shipper and producer (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 001-38770, filed on May 21, 2024)
10.3+	2020 Equity Incentive Plan effective as of September 1, 2020 (incorporated by reference to Exhibit 10.1 of Form8-K, File No. 001-38770, filed on September 1, 2020)
10.4+	Share Compensation Plan (incorporated by reference to Exhibit 10.10 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.5	Agreement for the Construction, Ownership, and Operation of Midstream Assets in AMI Area D of Northern Pennsylvania effective the 1st day of January, 2012, by and between Statoil Pipelines, LLC, a Delaware limited liability company formerly known as StatoilHydro Pipelines, LLC, Epsilon Midstream LLC, a Pennsylvania limited liability company, and Appalachia Midstream Services, L.L.C., an Oklahoma limited liability company (incorporated by reference to Exhibit 10.11 of Form 10, File No. 001-38770, filed on December 21, 2018)
10.6+	Jason Stabell Executive Employment Agreement (incorporated by reference to Exhibit 10.2 of Form 8-K, File No. 001-38770, filed on June 24, 2022)
10.7+	Andrew Williamson Executive Employment Agreement (incorporated by reference to Exhibit 10.4 of Form 8-K, File No. 001-38770, filed on June 24, 2022)

10.8	Credit Agreement, dated as of June 28, 2023, by and among Epsilon Energy USA Inc., Frost Bank, as agent and issuing bank, and the lenders from time to time party hereto (incorporated by reference to Exhibit 10.8 of Form 10-K, File No. 001-38770, filed on March 21, 2024)
10.9	Participation Agreement with HWN Energy, Ltd dated October 22, 2024 (incorporated by reference to Exhibit 10.1 of Form 8-K, File No. 001-38770, filed on October 28, 2024)
11.0	Membership Interest Purchase Agreement dated August 11, 2025, among the Sellers party thereto, Peak Exploration & Production, LLC, Epsilon Energy USA, Inc., Epsilon Energy Ltd., and Yorktown Energy Partners XI, L.P. (as Sellers' Representative) (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated August 11, 2025)
11.1	Membership Interest Purchase Agreement dated August 11, 2025, among Yorktown Energy Partners XI, L.P., Peak BLM Lease LLC, Epsilon Energy USA, Inc., and Epsilon Energy Ltd. (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K dated August 11, 2025)
19.1	Insider Trading Policy (incorporated by reference to Exhibit 19.1 of Form 10-K, File No. 001-38770, filed on March 19, 2025)
21.1	Subsidiaries of the Registrant (incorporated by reference to Exhibit 21.1 of Form 10, File No. 001-38770, filed on December 21, 2018)
23.1*	Consent of DeGolyer and MacNaughton
23.2*	Consent of BDO USA, P.C.
23.3*	Consent of Cawlie, Gillespie & Associates
31.1*	Rule 13a-14(a)/15d-14(a) Certification.
31.2*	Rule 13a-14(a)/15d-14(a) Certification.
32.1**	Section 1350 Certifications.
32.2**	Section 1350 Certifications.
97.1	Epsilon Energy Ltd. Clawback Policy (incorporated by reference to Exhibit 97.1 of Form 10-K, File No. 001-38770, filed on March 21, 2024)
99.1*	Summary Reserve Report – DeGolyer and MacNaughton
99.2*	Summary Reserve Report – Cawlie, Gillespie & Associates

101.INS*	Inline XBRL Instance Document.
101.SCH*	Inline XBRL Taxonomy Extension Schema Document.
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith.
** Furnished herewith.
+ Denotes a management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on March 27, 2026.

EPSILON ENERGY LTD.

By: /s/ *J. Andrew Williamson*
J. Andrew Williamson
Chief Financial Officer
(duly authorized to sign on behalf of the registrant)

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

Signature	Title	Date
/s/ Jason Stabell Jason Stabell	Chief Executive Officer (Principal Executive Officer)	March 27, 2026
/s/ Andrew Williamson Andrew Williamson	Chief Financial Officer (Principal Financial and Accounting Officer)	March 27, 2026
/s/ John Lovoi John Lovoi	Chairman of the Board	March 27, 2026
/s/ Jason Stankowski Jason Stankowski	Director	March 27, 2026
/s/ Tracy Stephens Tracy Stephens	Director	March 27, 2026
/s/ David Winn David Winn	Director	March 27, 2026
/s/ Nicola Maddox Nicola Maddox	Director	March 27, 2026
/s/ Jack E. Vaughn Jack E. Vaughn	Director	March 27, 2026
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director	March 27, 2026

Exhibit 23.1

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 27, 2026

Epsilon Energy Ltd.
500 Dallas, Suite 1250
Houston, Texas 77002

Ladies and Gentlemen:

We hereby consent to the reference to DeGolyer and MacNaughton and to the incorporation of the estimates contained in our reports entitled "Report as of December 31, 2025 on Reserves and Revenue of Certain Properties with interests attributable to Epsilon Energy Ltd" and "Report as of December 31, 2025 on Reserves and Revenue of Certain Properties with interests attributable to Epsilon Energy Ltd. NI 51-101" in Part 1 and in the "Supplemental Information to Consolidated Financial Statements (Unaudited)" portion of the Annual Report on Form 10-K of Epsilon Energy Ltd. for the year ended December 31, 2025 (the Annual Report). We further consent to the inclusion of our report of third party dated February 12, 2026, relating to our independent evaluation of the estimated proved oil, condensate, natural gas liquids, and gas reserves, as of December 31, 2025, attributable to Epsilon Energy Ltd. in the Annual Report.

We also hereby consent to the incorporation by reference of the foregoing in the Registration Statements on Form S-3 (Nos. 333-292703 and 333-292704) and Form S-8 (No. 333-248539) of Epsilon Energy Ltd. of our report dated February 12, 2026, filed with this Annual Report on Form 10-K.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-292703 and 333-292704) and Form S-8 (No. 333-248539) of Epsilon Energy, Ltd. of our report dated March 27, 2026, relating to the consolidated financial statements, which appears in this Annual Report on Form 10-K.

/s/ BDO USA, P.C.
Houston, Texas

March 27, 2026

Exhibit 23.3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the references to our firm, in the context in which they appear, and to the references to, and the inclusion of our summary reserve report dated January 15, 2026, and oil, natural gas and NGL reserves estimates and forecasts of economics as of December 31, 2025, each included in or made part of this Annual Report on Form 10-K of Epsilon Energy Ltd. We also consent to the incorporation by reference of such report in the Registration Statement on Form S-3 (No. 333-269267) and the Registration Statement on Form S-8 (No. 333-248539), each filed with the U.S. Securities and Exchange Commission.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

J. Zane Meekins, P.E.
Executive Vice President

Fort Worth, Texas
March 27, 2026

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
pursuant to Rule 13a-14(a)/15d-14(a)

I, Jason Stabell, Chief Executive Officer of Epsilon Energy Ltd., certify that:

1. I have reviewed this Annual Report on Form 10-K of Epsilon Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 27, 2026

/s/ Jason Stabell
Jason Stabell
Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
pursuant to Rule 13a-14(a)/15d-14(a)

I, J. Andrew Williamson, Chief Financial Officer of Epsilon Energy Ltd., certify that:

1. I have reviewed this Annual Report on Form 10-K of Epsilon Energy Ltd.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 27, 2026

/s/ J. Andrew Williamson
J. Andrew Williamson
Chief Financial Officer

Exhibit 32.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Epsilon Energy Ltd. (the "Corporation") on Form 10-K for the period ending December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Corporation.

Date: March 27, 2026

/s/ Jason Stabell
Jason Stabell
Chief Executive Officer

Exhibit 32.2

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Epsilon Energy Ltd. (the "Corporation") on Form 10-K for the period ending December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Corporation.

Date: March 27, 2026

/s/ J. Andrew Williamson
J. Andrew Williamson
Chief Financial Officer

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 12, 2026

Epsilon Energy Ltd.
500 Dallas Street
Suite 1250
Houston, Texas 77002

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2025, of the extent and value of the estimated net proved oil, condensate, natural gas liquids (NGL), and gas reserves of certain properties in which Epsilon Energy Ltd. (Epsilon) has represented it holds an interest. This evaluation was completed on February 12, 2026. The properties evaluated herein consist of working and royalty interests located in the States of New Mexico, Pennsylvania, and Texas in the United States and the Province of Alberta in Canada. Epsilon has represented that these properties account for 50.64 percent on a net gas equivalent basis of Epsilon's net proved reserves as of December 31, 2025. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Epsilon.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2025. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Epsilon after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, impact fees, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Epsilon to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Epsilon, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a discount rate of 10 percent per year compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Epsilon and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Epsilon with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

Definition of Reserves

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a)
(1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using established production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration

of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

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

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plan provided by Epsilon, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Epsilon.

Epsilon has represented that its senior management is committed to the development plan provided by Epsilon and that Epsilon has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Epsilon from wells drilled through December 31, 2025, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of daily and monthly production data available for certain properties only through October 2025. Estimated cumulative production, as of December 31, 2025, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 2 months.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil, condensate, and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at the pressure base of the state or province in which the quantities are located. Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include both associated and nonassociated gas.

At the request of Epsilon, liquid reserves estimated herein were converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Epsilon. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, and NGL Prices

Epsilon has represented that the oil, condensate, and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Epsilon supplied differentials to a West Texas Intermediate price of $65.34 per barrel and the prices were held constant thereafter. The volume-weighted average prices attributable to the estimated proved reserves over the lives of the properties were $64.36 per barrel of oil and condensate and $19.18 per barrel of NGL.

Gas Prices

Epsilon has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. Epsilon supplied differentials to a Henry Hub price of $3.39 per million Btu and the prices were held constant thereafter. Btu factors provided by Epsilon were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $2.646 per thousand cubic feet of gas.

Production Taxes and Impact Fees

For properties located in New Mexico, Texas and Alberta, Canada, production taxes were calculated using rates provided by Epsilon. For wells located in Pennsylvania, and in accordance with state law, an annual impact fee is assessed over the course of the first 15 years of production after the well is drilled. The amount of the annual fee imposed is adjusted annually on a sliding scale based on the average price of gas for each given year.

Royalties

Properties evaluated herein that are located in Alberta, Canada are subject to applicable royalties under the Modernized Royalty Framework, effective January 1, 2017.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses and future capital expenditures, provided by Epsilon and based on existing economic conditions, were held constant for the lives of the properties. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied.

> Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Epsilon and were not adjusted for inflation. At the request of Epsilon, abandonment costs and any associated negative future net revenue have been included herein for those proved developed properties for which reserves were estimated to be zero. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

DeGolyer and MacNaughton has performed an independent evaluation of the extent and value of the estimated net proved oil, condensate, NGL, and gas reserves of certain properties in which Epsilon has represented it holds an interest. The estimated net proved reserves, as of December 31, 2025, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and millions of cubic feet of gas equivalent (MMcfe):

Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2025				
	Oil and Condensate (Mbbl)	NGL (Mbbl)	Sales Gas (MMcf)	Gas Equivalent (MMcfe)
Proved Developed	783	314	63,874	70,453
Proved Undeveloped	326	114	5,913	8,556
Total Proved	**1,109**	**428**	**69,787**	**79,009**

Note: Liquid reserves estimated herein were converted to gas equivalent using an energy equivalent factor of 1 barrel of liquids per 6,000 cubic feet of gas equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2025, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	Total Proved (M$)
Future Gross Revenue	225,940	264,236
Production Taxes and Impact Fees	5,250	7,203
Operating Expenses	92,162	104,322
Capital Costs	0	10,108
Abandonment Costs	7,492	7,660
Future Net Revenue	121,036	134,943
Present Worth at 10 Percent	73,428	78,605

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2025, estimated reserves.

DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Epsilon. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Epsilon. DeGolyer and MacNaughton has used all assumptions, procedures, data, and methods that it considers necessary to prepare this report.

Submitted,
/s/ DeGolyer and MacNaughton
DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

CERTIFICATE of QUALIFICATION

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am an Executive Vice President with DeGolyer and MacNaughton, which firm did prepare this report of third party addressed to Epsilon dated
February 12, 2026, and that I, as Executive Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 15 years of experience in oil and gas reservoir studies and reserves evaluations.

/s/ Dilhan Ilk
Dilhan Ilk, P.E.
Executive Vice President
DeGolyer and MacNaughton

CAWLEY, GILLESPIE & ASSOCIATES, INC.

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January 15, 2026

Mr. Henry N. Clanton
Chief Operating Officer
Epsilon Energy USA, Inc.
500 Dallas Street, Suite 1250
Houston, TX 77002

Re: Evaluation Summary – SEC Pricing
Epsilon Energy Ltd. Interests
Campbell, Converse & Johnson Counties, Wyoming
Proved Reserves
As of December 31, 2025

Dear Mr. Clanton:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the Epsilon Energy Ltd. interests in properties located in various counties in Wyoming. It is our understanding that the proved reserves estimated in this report constitute 100 percent of all proved reserves owned by Epsilon Energy Ltd..

This report, completed on January 15, 2026, utilized an effective date of December 31, 2025 and was prepared using constant prices and costs and conforms to Item 1202(a)(8) of Regulation S-K and the other rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). This report has been prepared for use in filings with the SEC. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the reserves are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved
Net Reserves					
Oil	– Mbbl	3,179.0	38.0	4,932.9	8,150.0
Gas	– MMcf	11,939.7	36.0	4,609.2	16,584.9
NGL	– Mbbl	1,280.5	4.8	638.5	1,923.9
Revenue					
Oil	– M$	198,212.7	2,370.9	307,567.6	508,151.2
Gas	– M$	30,985.2	93.9	12,031.4	43,110.4
NGL	– M$	36,924.5	135.3	18,030.4	55,090.3
Severance Taxes	– M$	16,100.4	157.3	20,426.6	36,684.3
Ad Valorem Taxes	– M$	15,703.6	153.4	19,435.1	35,292.1
Operating Expenses	– M$	131,520.4	1,910.7	86,721.6	220,152.8
Investments	– M$	4,999.3	120.3	96,863.0	101,982.7
Net Operating Income (BFIT)	– M$	97,798.6	258.3	114,183.0	212,240.0
Discounted at 10%	– M$	59,683.5	222.0	47,663.6	107,569.0

In accordance with the SEC guidelines, the operating income (BFIT) has been discounted at an annual rate of 10% to determine its "present worth". The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The annual average Henry Hub spot market gas price of $3.387 per MMBtu and the annual average WTI Cushing spot oil price of $65.34 per barrel were used in this report. In accordance with the Securities and Exchange Commission guidelines, these prices are determined as an unweighted arithmetic average of the first-day-of-the-month price for 12 months prior to the effective date of the evaluation. Oil and gas prices were held constant and were adjusted for each property based on historical differentials. Deductions were applied to the net gas volumes for fuel and shrinkage. The adjusted volume-weighted average product prices over the life of the proved properties are $62.35 per barrel of oil, $2.60 per Mcf of gas, and $29.50 per barrel of NGL.

Operating expenses and investments were supplied by Epsilon Energy Ltd. and reviewed for reasonableness. Investments include capital costs for both future development and abandonment. "Other deductions" are variable expenses that are a function of oil, gas and water volumes. Severance taxes were forecast based on published rates. Ad valorem tax rates were scheduled by county based on historical data. Neither expenses nor investments were escalated.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Epsilon Energy Ltd.. Ownership interests were supplied by Epsilon Energy Ltd. and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc.

Cawley, Gillespie & Associates, Inc. is independent with respect to Epsilon Energy Ltd. as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers ("SPE Standards"). Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

Our work papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

*/s/ J. Zane Meekins, P.E.*__
J. Zane Meekins, P.E.
Executive Vice President

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693