UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended June 30, 2021

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

For the transition period from to

Commission File Number 001-32942

EVOLUTION PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Nevada	**41-1781991**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079
(Address of principal executive offices and zip code)
(713) 935-0122
(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange On Which Registered
Common Stock, $0.001 par value	EPM	NYSE American

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

None
(Title of Class)

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

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

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

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

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

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

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates on December 31, 2020, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $2.80 on the NYSE American was $86,002,899.

The number of shares outstanding of the registrant's common stock, par value $0.001, as of September 10, 2021, was 33,514,952.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement related to the registrant's 2021 Annual Meeting of Stockholders to be filed within 120 days of the end of the fiscal year covered by this report are incorporated by reference into Part III of this report.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES
2021 ANNUAL REPORT ON FORM 10-K

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We use the terms, "EPM," "Company," "we," " us," and "our" to refer to Evolution Petroleum Corporation, and unless the context otherwise requires, its wholly-owned subsidiaries.

FORWARD-LOOKING STATEMENTS

This Form 10-K and the information referenced herein contains forward-looking statements within the meaning of the Private Securities Litigations Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. The words "plan," "expect," "project," "estimate," "assume," "believe," "anticipate," "intend," "budget," "forecast," "predict" and other similar expressions are intended to identify forward-looking statements. These statements appear in a number of places and include statements regarding our plans, beliefs or current expectations, including the plans, beliefs and expectations of our officers and directors. When considering any forward-looking statement, you should keep in mind the risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include the timing and extent of changes in commodity prices for oil and natural gas, operating risks and other risk factors as described in Part I, Item 1A, "Risk Factors" and elsewhere in this report and as also may be described from time to time in our future reports we file with the Securities and Exchange Commission. You should read such information in conjunction with our consolidated financial statements and related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not currently perceive them to be material. Such factors could cause results to differ materially from our expectations.

Forward-looking statements speak only as of the date they are made, and we do not undertake to update these statements other than as required by law. You are advised, however, to review any further disclosures we make on related subjects in our periodic filings with the Securities and Exchange Commission.

GLOSSARY OF SELECTED PETROLEUM INDUSTRY TERMS

Term	Definition
Bbls	Barrels of oil or natural gas liquids.
BCF	Billion cubic feet.
BFPD	Barrels of fluid per day.
BOE	Barrels of oil equivalent. BOE is calculated by converting 6 MCF of natural gas to 1 Bbl of oil which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.
BOEPD	Barrels of oil equivalent per day.
BOPD	Barrels of oil per day.
BTU	British Thermal Unit: the standard unit of measure of energy equal to the amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit. One Bbl of oil is typically 5.8 MMBTU, and one standard MCF is typically one MMBTU.
CO_2	Carbon Dioxide; CO_2 is a gas that can be found in naturally occurring reservoirs, is typically associated with ancient volcanoes, is a major byproduct from manufacturing and power production, and is also utilized in enhanced oil recovery through injection into an oil reservoir.
Developed Reserves	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 a means not involving a well.
EOR	Enhanced Oil Recovery; projects that involve injection of heat, miscible or immiscible gas, or chemicals into oil reservoirs, typically following full primary and secondary waterflood recovery efforts, in order to gain incremental recovery of oil from the reservoir.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped within or related to the same geologic structural features and/or stratigraphic features.*
Farmout	Sale or transfer of all or part of the operating rights from the working interest owner (the assignor or farmout party), to an assignee (the farm-in party) who assumes all or some of the burden of development, in return for an interest in the property. The assignor may retain an overriding royalty or any other type of interest. For Federal tax purposes, a farmout may be structured as a sale or lease, depending on the specific rights and carved out interests retained by the assignor.
Gross Acres or Gross Wells	The total acres or number of wells participated in, regardless of the amount of working interest owned.
Horizontal Drilling	Involves drilling horizontally out from a vertical well bore, thereby potentially increasing the area and reach of the well bore that is in contact with the reservoir.
Hydraulic Fracturing	Involves pumping a fluid with or without particulates into a formation at high pressure, thereby creating fractures in the rock and leaving the particulates in the fractures to ensure that the fractures remain open which potentially increases the ability of the reservoir to produce oil or gas.
LOE	Means Lease Operating Expense(s), a current period expense incurred to operate a well.
MMBBL	One million barrels.
MBO	One thousand barrels of oil.
MBOE	One thousand barrels of oil equivalent.
MCF	One thousand cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature.
MMCF	One million cubic feet of natural gas at standard conditions, being approximately sea level pressure and 60 degrees Fahrenheit temperature.
MMBOE	One million barrels of oil equivalent.
MMBTU	One million British Thermal Units.
Mineral Royalty Interest	A royalty interest that is retained by the owner of the minerals underlying a lease. See "Royalty Interest."
Net Acres or Net Wells	The sum of the fractional working interests owned in gross acres or gross wells.
NGL	Natural Gas Liquids; the combination of ethane, propane, butane and natural gasoline that can be removed from natural gas through processing, typically through refrigeration plants that utilize low temperatures, or through plants that utilize compression, temperature reduction and expansion to a lower pressure.
NYMEX	New York Mercantile Exchange.
OOIP	Original Oil in Place; an estimate of the barrels originally contained in a reservoir before any production therefrom.
Operator	An oil and gas joint venture participant that manages the joint venture, pays venture costs and bills the venture's non-operators for their share of venture costs. The operator is also responsible to market all oil and gas production, except for those non-operators who take their production in-kind.

Overriding Royalty Interest or ORRI	A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of. See "Royalty Interest."
Permeability	The measure of ease with which a fluid can move through a reservoir. The unit of measure is a darcy (d), or any metric derivation thereof, such as a millidarcy (md), where one darcy equals 1,000 millidarcys. Extremely low permeability of 10 millidarcys, or less, are often associated with source rocks, such as shale. Extraction of hydrocarbons from a source rock is more difficult than a sandstone reservoir where permeability typically ranges one to two darcys or more.
Porosity	The relative volume of the pore space (or open area) compared to the total bulk volume of the reservoir, stated in percent. Higher porosity rocks provide more storage space for hydrocarbon accumulations than lower porosity rocks in a given cubic volume of reservoir.
Producing Reserves	Any category of reserves that have been developed and production has been initiated.*
Proved Developed Reserves	Proved Reserves 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 a means not involving a well.
Proved Developed Nonproducing Reserves	Proved Reserves that have been developed and no material amount of capital expenditures are required to bring on production, but production has not yet been initiated due to timing, markets, or lack of third party completed connection to a gas sales pipeline.*
Proved Developed Producing Reserves ("PDP")	Proved Reserves that have been developed and production has been initiated.*
Proved Reserves	Estimated quantities of oil, natural gas, and natural gas liquids which geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*
Proved Undeveloped Reserves ("PUD")	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.* (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 or by other evidence using reliable technology establishing reasonable certainty.
Present Value	When used with respect to oil and gas reserves, present value means the estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs to be incurred in developing and producing the proved reserves) computed using a discount factor and assuming continuation of existing economic conditions.
Productive Well	A well that is producing oil or gas or that is capable of production.
PV-10	Means 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.
Royalty or Royalty Interest	1) The mineral owner's share of oil or gas production (typically between 1/8 and 1/4), free of costs, but subject to severance taxes unless the lessor is a government. In certain circumstances, the royalty owner bears a proportionate share of the costs of making the natural gas saleable, such as processing, compression, and gathering. 2) When a royalty interest is coterminous with and carved out of an operating or working interest, it is an "Overriding Royalty Interest," which also may generically be referred to as a Royalty.
Shut-in Well	A well that is not on production, but has not been plugged and abandoned. Wells may be shut-in in anticipation of future utility as a producing well, plugging and abandonment or other use.

Standardized Measure	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 are 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 accounting standards generally accepted in the United States of America ("GAAP").
Undeveloped Reserves	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.*
Working Interest	The interest in the oil and gas in place which is burdened with the cost of development and operation of the property. Also called the operating interest.
Workover	A remedial operation on a completed well to restore, maintain, or improve the well's production.

* This definition may be an abbreviated version of the complete definition as defined by the SEC in Rule 4-10(a) of Regulation S-X.

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PART I

Item 1. Business

Note: *See Glossary of Selected Petroleum Industry Terms starting on page iii*

General

Evolution Petroleum Corporation is an oil and natural gas company focused on delivering a sustainable dividend yield to its shareholders through the ownership, management, and development of producing oil and natural gas properties. The Company's long-term goal is to build a diversified portfolio of oil and natural gas assets primarily through acquisition, while seeking opportunities to maintain and increase production through selective development, production enhancement, and other exploitation efforts on its properties.

Our producing assets consist of our interests in the Delhi Holt-Bryant Unit in the Delhi field in Northeast Louisiana, a CO_2 enhanced oil recovery ("EOR") project, our interests in the Hamilton Dome field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir, our interests in the Barnett Shale located in North Texas, a natural gas producing shale reservoir, and overriding royalty interests in two onshore central Texas wells.

Our interests in the Delhi field consist of a 23.9% working interest, with an associated 19.0% revenue interest and separate overriding royalty and mineral interests of 7.2% yielding a total net revenue interest of 26.2%. The field is operated by Denbury Onshore LLC ("Denbury"), a subsidiary of Denbury Inc.

On November 1, 2019, the Company acquired non-operated working interests in the Hamilton Dome field consisting of a 23.5% working interest, with an associated 19.7% revenue interest (inclusive of a small overriding royalty interest). The field is operated by Merit Energy Company ("Merit"), a private oil and natural gas company, who owns the vast majority of the remaining working interest in the Hamilton Dome field. Our acquired interest in Hamilton Dome aligned with the Company's strategy of adding long-lived, low decline reserves expected to be supportive of our dividend over the long-term.

On May 7, 2021, the Company acquired non-operated working interests in the Barnett Shale consisting of approximately 21,000 net acres held by production across nine North Texas counties in the Barnett Shale (the "Barnett Shale Acquisition"). The acreage has an average working interest of 17.3% and associated average revenue interest of 14.2% (inclusive of overriding royalty interests). At the time of the Barnett Shale Acquisition, approximately 90% of the wells acquired were operated by Blackbeard Operating LLC ("Blackbeard"), while the remaining 10% were operated by seven other operators. After the closing of the Barnett Shale Acquisition, Blackbeard announced the sale of its interests to Diversified Energy Company PLC ("Diversified Energy"), which subsequently closed in July of 2021. At present, Blackbeard is still the operator of the assets under a transition services agreement with Diversified Energy. However, after the transition, Diversified Energy will take over operations of the assets.

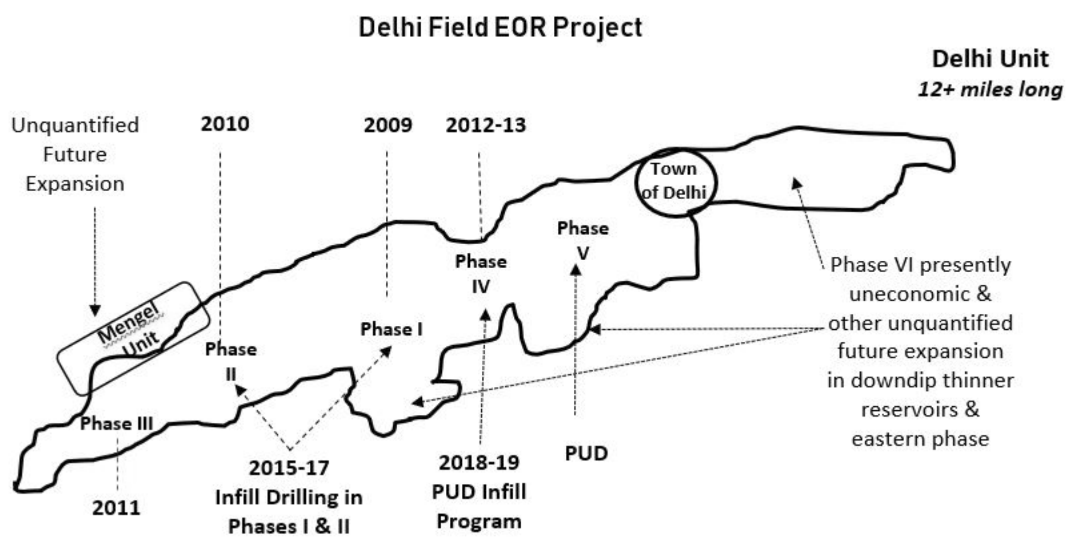
Significant Activity in Fiscal 2021

- Closed the Barnett Shale Acquisition on May 7, 2021, which included total proved reserves of 13.1 MMBOE as of June 30, 2021 as estimated by DeGolyer & MacNaughton ("D&M"), an independent reservoir engineering firm.
- Returned to shareholders $4.3 million in cash dividends in fiscal 2021. The Company has paid out to shareholders more than $74.5 million in cash dividends since inception of the dividend program in December 2013.
- Generated $3.7 million in operating income before impairments.
- Funded our operations, development capital expenditures, and dividends out of operating cash flow.
- Proved oil equivalent reserves at June 30, 2021, were 23.4 MMBOE, a 129% increase from the previous year primarily due to the acquisition of interests in the Barnett Shale in May 2021.
- Primarily driven by proved oil and gas property impairments of $9.6 million and $15.2 million recorded during the first and second fiscal quarters of 2021, respectively, we recognized a net loss of $16.4 million, or $(0.49) per common share.
- We completed the NYMEX WTI oil swaps entered into during fiscal year 2020, and have not entered into any new oil and natural gas derivatives as of June 30, 2021.
- Denbury, whose subsidiary operates the Delhi field, emerged from bankruptcy on September 18, 2020, and returned to conformance projects with a refreshed capital budget after a period of no conformance spending.

Delhi Field - Enhanced Oil Recovery CO_2 Flood - Onshore Louisiana

The Company purchased the Delhi field in September 2003. In May 2006, the Company conveyed its working interest in the field to Denbury for $50 million for the purpose of installing an EOR project; we retained a 23.9% reversionary working interest upon payout of the project, as defined in the purchase and sale agreements. Today, our interests include a 23.9% working interest and a 7.2% royalty interest with a total net revenue interest of 26.2%. Delhi field is located in northeast Louisiana in Franklin, Madison, and Richland parishes and encompasses approximately 13,600 unitized acres.

The Delhi field was discovered in the mid-1940s and has had a prolific production history totaling approximately 195 MMBbls of oil through primary and limited secondary recovery operations. Since EOR production began in March 2010, the Unit has produced over 23.0 MMBbls of oil. For fiscal 2021, average gross daily oil production at Delhi was 4,281 BOPD and 977 bbls NGLs per day (5,258 BOEPD).



After the May 2006 conveyance, Denbury as the operator originally planned six primary phases for the installation of the CO_2 flood in the Delhi field. Four of these six phases have been completed as of June 30, 2021, and two remain undeveloped. One of the remaining two phases (Phase V) is reflected as proved undeveloped in our current reserves report and the other (Phase VI) was removed from proved reserves as it was not deemed economic due to distant location and oil price.

In June 2013, following an adverse fluid release event that consisted of the uncontrolled release of CO_2, water, natural gas, and a small amount of oil from a previously plugged well in the southwest part of the field, the operator suspended CO_2 injection in most of the southwestern tip of the field. The operator has fully remediated the affected area, and has isolated that part of the field with a water curtain, thus removing the area from the CO_2 flood.

An NGL extraction plant was completed and began processing in December 2016. The plant allows for the sale of NGLs, improves CO_2 flood efficiency, and provides the extracted methane as a source of power for plant reducing operating expenses.

Phase V development started in fiscal 2017 with the water curtain and related infrastructure program. The first pad commenced injections in fiscal 2019 with the second pad starting in the second quarter of fiscal 2020. Additional Delhi Phase V development has been delayed due to Denbury's restructuring in fiscal 2021.

The total gross purchased CO_2 volume was 18 BCF for fiscal 2021. In February 2020, the CO_2 purchase line to Delhi was shut-in by the pipeline operator for extensive repairs. No CO_2 was purchased from the shut-in date through October 2020. During the pipeline repairs, the $CO\text{-}_2$ recycle facilities continued to operate providing approximately 80% of the historic total injected CO_2 volumes to Delhi. The decrease in production within the field was primarily a result of lower injection volumes reducing reservoir pressure. CO2 purchases resumed in November 2020 at a limited level, and resumption of desired purchase volumes is expected during fiscal 2022 which is projected to increase reservoir pressure.

At June 30, 2021, the Company had total proved reserves of 8.5 MMBOE at Delhi, which was comprised of 6.5 MMBOE of oil and 2.0 MMBOE of NGLs as estimated by our independent petroleum engineering firm. The following table sets forth our estimated proved reserves as of June 30, 2021. For additional reserve information see Note 20 to our consolidated financial statements in Item 8.

Reserve Category - Delhi field	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)*
PROVED				
Developed Producing (79% of Proved)	4,879	1,784	—	6,663
Undeveloped (21% of Proved)	1,605	209	—	1,814
TOTAL PROVED	6,484	1,993	—	8,477
Product Mix	76 %	24 %	— %	100 %

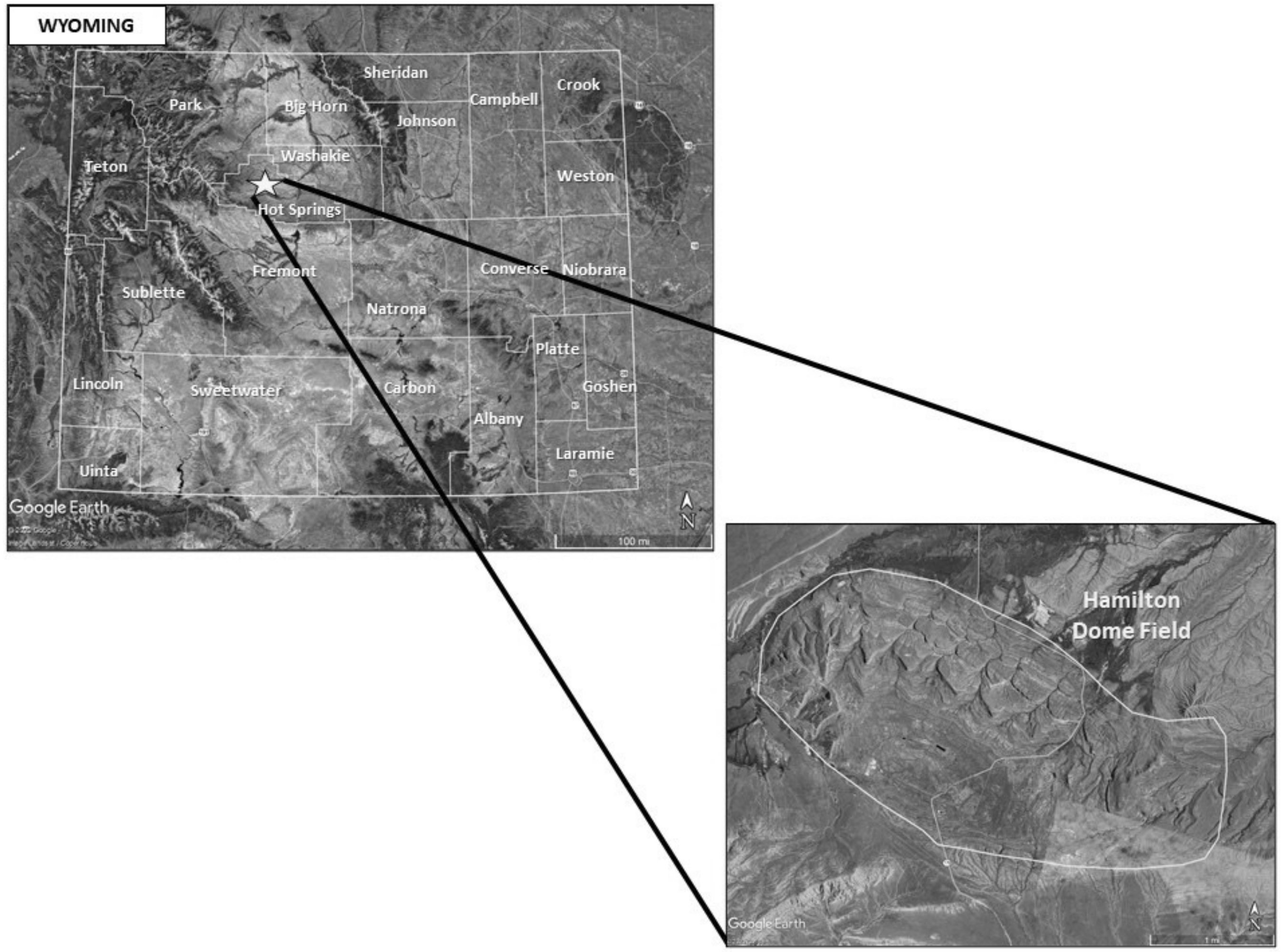
*Equivalent oil reserves are defined as six MCF of gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Hamilton Dome - Historical, Low Decline Waterflood - Hot Springs County, Wyoming

On November 1, 2019, the Company acquired certain mineral interests in the Hamilton Dome field from Merit, who owns the vast majority of the remaining working interest in the field. The Hamilton Dome field is located in the southwest part of the Big Horn Basin in northwest Wyoming about twenty miles northwest of Thermopolis in Hot Springs County.

Our interest includes a 23.5% working interest and an associated 19.7% revenue interest (inclusive of a small overriding royalty interest) in the approximately 3,160 acre unitized field. The Hamilton Dome field has been operated by Merit since 1995. Under Merit's operations, the wells in the Hamilton Dome field are produced using secondary recovery water flood methods via electric submersible pumps (ESP) and rod pumps. Typical workovers in the field include rod repair, ESP repair, injector acid jobs, and wellbore cleanouts.

The Hamilton Dome field was discovered in 1918 and has produced over 160 MMBO. Production from this field is 100% oil and is currently averaging low single-digit decline rates. The primary producing reservoirs in the field are the Tensleep and Phosphoria with an approximate depth of 3,000 feet. Average gross daily production was 1,987 BOPD for the year ended June 30, 2021. Produced oil from the field is subject to Western Canadian Select pricing.



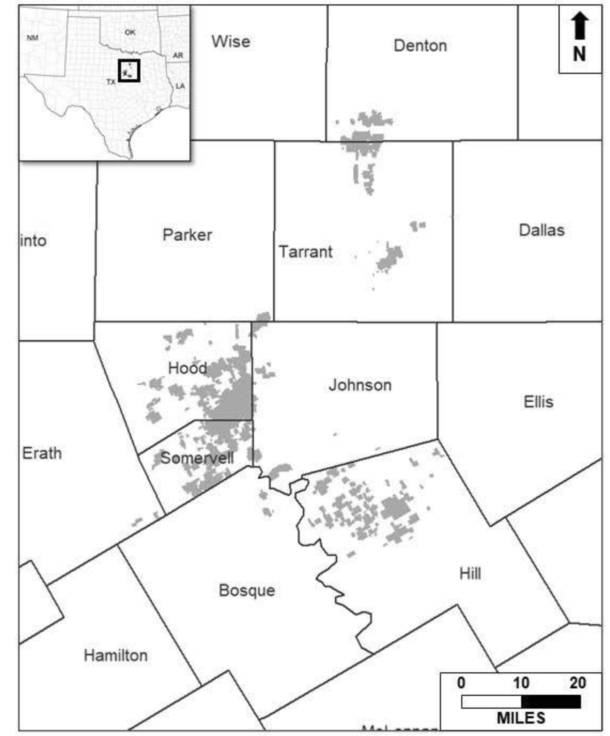
At June 30, 2021, the Company has total net proved reserves of 1.9 MMBOE at Hamilton Dome which was entirely comprised of oil as estimated by our independent reservoir engineering firm. The following table sets forth our estimated proved reserves as of June 30, 2021 for our Hamilton Dome field. For additional reserve information see Note 20 to our consolidated financial statements in Item 8.

Reserve Category - Hamilton Dome field	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)*
PROVED				
Developed Producing (100% of Proved)	1,851	—	—	1,851
Undeveloped (0% of Proved)	—	—	—	—
TOTAL PROVED	1,851	—	—	1,851
Product Mix	100 %	— %	— %	100 %

*Equivalent oil reserves are defined as six MCF of gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Barnett Shale - Mature, Low Decline Natural Gas Production - North Texas

On May 7, 2021, the Company acquired non-operated working interests in the Barnett Shale from TG Barnett Resources, LP, a wholly owned subsidiary of Tokyo Gas Americas, Ltd. The acquired assets consist of approximately 21,000 net acres held by production across nine North Texas counties (Bosque, Denton, Erath, Hill, Hood, Johnson, Parker, Somervell, and Tarrant) in the Barnett Shale.



Our interest includes an average working interest of 17.3% and associated average revenue interest of 14.2%. At the time of acquisition, approximately 90% of the wells acquired were operated by Blackbeard, while the remaining 10% were operated by seven other operators. After the close of the Barnett Shale Acquisition, Blackbeard announced the sale of its interests to Diversified Energy, which closed in July 2021.

The Barnett Shale was discovered as a natural gas resource play in the Newark East field in 1981; following completions of technology advancements in the 1990s, development of the Barnett Shale began in earnest in 1998. The majority of the wells included in our Barnett Shale assets were completed between 2007 and 2010 and are horizontals. The assets are characterized by mature, low-decline production. Average net daily production from the acquisition date of May 7, 2021 to June 30, 2021, was 4.3 MBOE per day. Commodities produced from our Barnett Shale assets include natural gas, oil and NGLs that are sold to Gulf Coast markets.

At June 30, 2021, the Company has total net proved reserves of 13.1 MMBOE in the Barnett Shale which is comprised of natural gas and NGLs with a small amount of oil, as estimated by our independent reservoir engineering firm. The following table sets forth our estimated proved reserves as of June 30, 2021 for our Barnett Shale assets. For additional reserve information, see Note 20 to our consolidated financial statements in Item 8.

Reserve Category - Barnett Shale field	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)*
PROVED				
Developed Producing (100% of Proved)	85	4,879	48,571	13,059
Undeveloped (0% of Proved)	—	—	—	—
TOTAL PROVED	85	4,879	48,571	13,059
Product Mix	1 %	37 %	62 %	100 %

Estimated Oil and Natural Gas Reserves and Estimated Future Net Revenues

The SEC sets rules related to reserve estimation and disclosure requirements for oil and natural gas companies. These rules require disclosure of oil and natural gas proved reserves by significant geographic area, using the trailing 12-month average 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, rather than year-end prices, and allows the use of new technologies in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Subject to limited exceptions, the rules also require that proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years.

There are numerous uncertainties inherent in estimating quantities of proved reserves and estimates of reserves quantities and values must be viewed as being subject to significant change as more data about the properties becomes available.

Summary of Oil & Gas Reserves for Fiscal Year Ended 2021

Our proved reserves at June 30, 2021, denominated in barrels of oil equivalent (BOE) using six MCF of gas and 42 gallons of NGLs to one barrel of oil conversion ratio, were estimated by our independent reservoir engineer, DeGolyer and MacNaughton ("D&M") which was formed in 1936. D&M has completed more than 23,000 projects in more than 100 countries. D&M was selected to estimate reserves primarily due to their expertise in CO_2-EOR projects and to ensure consistency with the operator of the Delhi field. The scope and results of their procedures are summarized in a letter from the firm, which is included as Exhibit 99.1 to this Annual Report on Form 10-K.

The following table sets forth our estimated proved reserves as of June 30, 2021. For additional reserve information, see Note 20 to our consolidated financial statements in Item 8. The NYMEX previous 12-month unweighted arithmetic average first-day-of-the-month price used to calculate estimated revenues was $49.72 per barrel of oil and $2.46 per MMBtu of natural gas. The net price per barrel of NGLs was $19.81, which does not have any single comparable reference index price. The NGL price was based on historical prices received. For periods for which no historical price information was available, we used comparable pricing in the geographic area. Pricing differentials were applied based on quality, processing, transportation, location and other pricing aspects for each individual property and product.

Reserves as of June 30, 2021

Reserve Category - Combined	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)*
PROVED				
Developed Producing (92% of Proved)	6,815	6,663	48,571	21,573
Undeveloped (8% of Proved)	1,605	208	—	1,813
TOTAL PROVED	8,420	6,871	48,571	23,386
Product Mix	36 %	29 %	35 %	100 %

*Equivalent oil reserves are defined as six MCF of gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

The following table presents a reconciliation of changes in our proved reserves by major property, on the basis of equivalent MBOE quantities.

Reconciliation of Changes in Proved Reserves by Major Property

	Delhi Field Proved Total
Proved reserves, MBOE	MBOE
June 30, 2020	8,746
Purchases	—
Production	(504)
Revisions (a)	235
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2021	8,477

(a) Positive revisions of 235 MBOE at Delhi field reflect operating cost reductions and improved NGL differential extending the reserves life of the field.

	Hamilton Dome Field Proved Total
Proved reserves, MBOE	MBOE
June 30, 2020	1,473
Purchases	—
Production	(143)
Revisions (a)	521
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2021	1,851

(a) Positive revisions of 521 MBOE reflect improved trailing twelve month SEC pricing and differentials, reactivation of shut-in production throughout the year, and reduced operating expenses. These factors resulted in wells remaining economic longer, extending the reserves life of the field.

	Barnett Shale Field Proved Total
Proved reserves, MBOE	MBOE
June 30, 2020	—
Purchases	13,299
Production	(240)
Revisions	—
Sales of minerals in place	—
Improved recovery, extensions and discoveries	—
June 30, 2021	13,059

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 reserves estimates require such estimates to be prepared by an independent petroleum engineering firm under the supervision of our President and Chief Executive Officer, Jason Brown, who has over 20 years of experience in the energy industry and is a Registered Professional Engineer (Petroleum) in the State of Texas. He earned his B.S. degree in chemical engineering from the University of Tulsa and his M.B.A. from the Mendoza School of Business at the University of Notre Dame. Such reserves estimates comply with generally accepted petroleum engineering and evaluation principles, definitions, and guidelines as established by the SEC.

The reserves information in this filing is based on estimates prepared by D&M. The person responsible for the preparation of the reserve report is a Senior Vice President and Division Manager of North America at D&M. He received a Bachelor of Science degree in Petroleum Engineering in 2003 from Istanbul Technical University and a Master's degree and Doctorate in Petroleum Engineering in 2005 and 2010, respectively, from Texas A&M University, and he has in excess of 10 years of experience in oil and gas reservoir studies and evaluations.

We provide D&M with our property interests, production, current operating costs, current production prices, and other information in order to prepare the reserve estimates. This information is reviewed by our President and Chief Executive Officer, designated operations personnel, and other members of management to ensure accuracy and completeness of the data prior to submission to D&M. The scope and results of D&M's procedures, as well as their professional qualifications, are summarized in the letter included as Exhibit 99.1 to this Annual Report on Form 10-K.

Proved Undeveloped Reserves

Our proved undeveloped reserves were 1,813 MBOE at June 30, 2021, with associated future development costs of approximately $8.6 million, which are associated with the Phase V development of Delhi field. The Company does not have any proved undeveloped reserves associated with its Hamilton Dome field or Barnett Shale asset.

During the year ended June 30, 2021 our proved undeveloped reserves changed as follows:

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Total Reserves (MBOE)
June 30, 2020	1,648	216	—	1,864
Revisions to previous estimates	(43)	(8)	—	(51)
Conversion to proved developed reserves	—	—	—	—
June 30, 2021	1,605	208	—	1,813

Fiscal year 2020 price declines resulted in a reclassification of a small volume of oil reserves from PDP to PUD at June 30, 2020. The decline in price led to currently producing wells becoming uneconomic at an earlier point in time than previously estimated. Due to the EOR unit nature of Delhi, this PDP reduction shifts those reserves to our PUD oil reserves as they are considered proved and expected to be recovered as a result of the development of our Phase V project. During fiscal year 2021, we experienced reductions in expenses and improvement of the NGL differential at Delhi which extended the economic life of the PDP reserves. This caused a revision to PUD reserves by shifting them from PUD to PDP. Additionally, changes to Phase V development timing, as further discussed below, have slightly decreased PUD reserves.

The initial assignment of proved undeveloped reserves in the Delhi field was made on June 30, 2010, which encompassed a large-scale CO_2 enhanced oil recovery project. The operator's original development plans for the field to be completed by June 30, 2015, within five years from the initial recording of such proved reserves, has not proceeded as originally scheduled as a result of the adverse fluid release event in the field in June 2013 and the resulting delay in reversion of our working interest. Expansion of the CO_2 flood to the remaining undeveloped eastern portion of the field commenced subsequent to reversion of our working interest in late calendar 2014 but was electively deferred by the operator shortly thereafter due to reductions in its cash flows and capital spending from the significant drop in oil prices. This project was further electively deferred as we began work on the NGL recovery plant field in February 2015. It was determined that the economics of development of the remaining eastern portion of the field would be significantly improved after the NGL plant was completed.

Authorization for construction of the NGL plant project occurred in fiscal 2015 and was completed in December 2016. Since completion of the plant, we have resumed work that had been suspended in late 2014 and further deferred until the NGL recovery plant was complete, including construction of the six-well water curtain program and related infrastructure required to precede the development of Phase V. All injection wells have been completed and injections from the second pad began in second quarter of fiscal 2020.

As of June 30, 2021, we have estimated total future net capital expenditures of approximately $8.6 million for remaining development of Phase V in the eastern part of the field, which we expect to commence in fiscal year 2023, however the timing is dependent on the field operator's available funds, capital spending plans, and priorities within its portfolio of properties.

We have been continuously developing the Delhi field and have spent over $48 million subsequent to reversion of our working interest in November 2014. Given the long-term nature of CO_2 EOR development projects, we believe that the remaining undeveloped reserves in the Delhi field satisfy the conditions to continue to be treated as proved undeveloped reserves because (1) we initially established the development plan for the Delhi field in 2010 and continue to follow that plan, as adjusted to incorporate the completion of the NGL plant in late 2016 and delays relating to the 2013 adverse fluid release event; (2) we have had significant ongoing development activities at this project that, as budgeted and currently being expended, reflect a significant and sufficient portion of remaining capital expenditures to convert proved undeveloped reserves to proved developed reserves; and (3) the operator has a historical record of completing the development of comparable long-term projects.

As of June 30, 2021, no proved reserves were attributed to (a) the area beneath the inhabited portion of the town of Delhi in the northeast and (b) the farthest east of the two remaining undeveloped sites in the eastern portion of the field (Phase VI) due to the current economics and other technical aspects of our future development plans. In addition, no proved reserves are currently attributed to three smaller reservoirs within the Unit in similar formations with similar production history due to the lower oil price utilized in our reserves calculation. We also do not have any proved reserves associated with our interests in the Mengel Sand, a separate interval within the Unit that is not currently producing, but has produced oil in the past.

Sales Volumes, Average Sales Prices and Average Production Costs

The following table shows the Company's sales volumes and average sales prices received for oil, NGLs, and natural gas for the periods indicated:

	Year Ended June 30, 2021		Year Ended June 30, 2020		Year Ended June 30, 2019	
Product	**Volume**	**Price**	**Volume**	**Price**	**Volume**	**Price**
Oil (Bbls)	554,888	$ 47.60	638,464	$ 44.76	626,879	$ 65.05
NGL (Bbls)	171,451	$ 21.36	106,159	$ 9.59	112,013	$ 21.87
Natural gas (Mcf)	963,496	$ 2.73	1,087	$ 1.90	459	$ 2.64
Average price per BOE*	886,922	$ 36.87	744,804	$ 39.74	738,968	$ 58.50
Production costs	**Amount**	**per BOE**	**Amount**	**per BOE**	**Amount**	**per BOE**
Production costs, excluding ad valorem and production taxes	$ 15,414,166	$ 17.38	$ 12,966,923	$ 17.41	$ 14,027,461	$ 18.98
Total production costs, including ad valorem and production taxes	$ 16,587,052	$ 18.70	$ 13,505,502	$ 18.13	$ 14,266,784	$ 19.31

*Equivalent oil reserves are defined as six MCF of gas and 42 gallons of NGLs to one barrel of oil conversion ratio which reflects energy equivalence and not price equivalence. Gas prices per MCF and NGL prices per barrel often differ significantly from the equivalent amount of oil.

Drilling Activity

Our productive drilling activity at Delhi field during the past three fiscal years ended June 30, 2021, was limited to five (1.2 net) producer wells completed in fiscal 2019. We completed one (0.24 net) CO_2 injection well during fiscal 2019. No dry wells were drilled in the past three fiscal years. There were no new wells drilled in fiscal 2020 or fiscal 2021.

In connection with establishing a six-well water curtain on two pads in advance of Phase V site development, during fiscal 2019 our operator drilled two (0.48 net) wells and completed three (0.72 net) wells. A pad consists of one gross water source well and two gross water injector wells. The northern pad commenced injection during fiscal 2019 and the southern pad became fully operational late in the second quarter of fiscal 2020 when capital expenditures for completion work concluded.

Barnett Shale acreage contains potential drilling locations; however, they are not included within our proved reserves as of June 30, 2021. Diversified Energy has recently acquired the assets and has not yet formalized a capital drilling budget for fiscal year 2022.

Hamilton Dome field is considered fully developed. No wells were drilled in fiscal 2021, and there are no plans to drill wells in fiscal 2022.

Present Activities

Starting in late third quarter 2021, the operator of the Delhi field resumed some capital conformance work to recomplete existing wells into different production zones, including recompleting a temporarily abandoned well in Test Site V. This work is still ongoing and too early to quantify the impact of these projects on the patterns. There are no significant drilling plans until Phase V development, expected to commence in 2023.

The Hamilton Dome operator is performing expense workovers within the field to maintain production and expects to plug four wells in first half of fiscal year 2022. There are currently no capital projects proposed within the field for fiscal year 2022.

The primary Barnett Shale operator has recently taken over as operator and has yet to formalize a budget, however they have expressed interest in identifying and performing remedial workovers to maintain and restore production.

For further discussion, see "Highlights for our fiscal year 2021" and "Capital Expenditures" within Item 7.

Delivery Commitments

As of June 30, 2021, we were not committed to provide a fixed and determinable quantity of oil, NGLs, or natural gas under existing agreements, nor do we currently intend to enter into any such agreements.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we own a working interest as of June 30, 2021.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	326	77	326	77
Natural gas	—	—	1,074	186	1,074	186
Total	—	—	1,400	263	1,400	263

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of June 30, 2021. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would allow production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

Field (1)	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Delhi Field, Louisiana	9,126	2,180	4,510	1,077	13,636	3,257
Hamilton Dome Field, Wyoming	5,908	1,389	—	—	5,908	1,389
Barnett Shale, Texas	123,777	20,918	—	—	123,777	20,918
Total(2)	138,811	24,487	4,510	1,077	143,321	25,564

(1) All acreage, including any undeveloped, nonproductive or undrilled acreage, is held by existing production as long as continuous production is maintained in the unit.

(2) This table excludes acreage attributable to small overriding royalty interests retained in various formations in the Texas Giddings Field area. Except for de minimis production that began on two leases during later fiscal 2019, none of such acreage is currently producing and our interests are subject to expiration if leases are not maintained by others or commercial production is not established. It does not currently appear likely that we will obtain any significant value from these interests and no reserves have been assigned to any of the Giddings interests.

When the Company acquired the Delhi field in 2003, the field had been fully developed through primary and secondary recovery methods and all of such acreage was reflected as developed acreage. With the addition of a CO_2-EOR project in the field, certain acreage is now reflected as undeveloped, due to the transition to using tertiary recovery methods. We estimate that our developed acreage currently includes 9,126 gross (2,180 net) acres in the Delhi field, with approximately 4,510 gross (1,077 net) acres attributable to the remaining undeveloped areas in the eastern part of the field.

At the Delhi field, our interests include all depths from the ground surface to the top of the Massive Anhydride. These depth rights include the Delhi Holt Bryant Unit (Tuscaloosa and Paluxy formations) which is currently under CO_2 flood, and the Mengel Sand Interval which is within the boundary of the field but is currently not producing. As the Delhi field is unitized per the State of Louisiana Department of Conservation order number 96-G-5, all acreage, including any undeveloped, non-productive or undrilled acreage is held by existing production as long as continuous production is maintained in the unit.

When the Company acquired its interests in the Hamilton Dome field on November 1, 2019, the field had been fully developed through primary recovery and therefore all acreage is reflected as developed acreage. The Tensleep and Phosphoria were permitted for commingling and unitized in 1996 following purchase of the field by Merit Energy in 1995. The Company estimates that our developed acreage includes 5,908 gross (1,389 net) acres in the Hamilton Dome field, with no acres attributable as undeveloped. As Hamilton Dome is unitized, all acreage is held by existing production as long as continuous production is maintained in the unit.

The Company acquired the Barnett Shale field on May 7, 2021, which is currently being developed through primary recovery. The Company estimates that our developed acreage includes 123,777 gross (20,918 net) acres in the Barnett Shale field, with no acres attributable as undeveloped.

For more complete information regarding current year activities, including oil and natural gas production, refer to Item 7.

Markets and Customers

Our production is marketed to third parties in a manner consistent with industry practices. In the United States of America market where we operate, oil, natural gas, and NGLs are readily transportable and marketable. We do not currently market our share of oil, natural gas, or NGLs production from the Delhi field, the Barnett Shale or from the Hamilton Dome field separately from the operators' shares of production. Although we have the right to take our working interest production in-kind, we are currently selling our production through the field operators pursuant to the delivery and pricing terms of their sales contracts. Under such arrangements, we typically do not know the identity of the buyers of production except in the case of the Delhi field where there is a sole buyer for oil and another for NGL's, and in the case of the Barnett Shale where there is a sole buyer for approximately all of the natural gas.

The oil from Delhi is currently transported from the field by pipeline, which results in better net pricing than the alternative of transportation by truck. Delhi oil production sells at Louisiana Light Sweet (“LLS”) pricing which generally trades at a premium to West Texas Intermediate (“WTI”) oil pricing. However, due to global market conditions, this premium was reduced during fiscal year ended 2021 versus fiscal year 2020. The LLS Gulf Coast average price differential over WTI, as quoted daily on the New York Mercantile Exchange (“NYMEX”), was approximately $1.75 during our fiscal year ended June 30, 2021, compared to $3.70 for the prior year. In the current fiscal year, the differential was impacted by market conditions over the fiscal year. NGL production is sold to a midstream processing company that fractionates the stream and sells the resulting hydrocarbons. The NGL revenues we receive are substantially reduced when the field oil realized price falls below $60 due to a capital recovery agreement with the operator; however, the impact is partially offset by corresponding reduced gas plant operating expense.

On November 1, 2019, Evolution acquired a non-operated interest in the Hamilton Dome field in Wyoming. All the field’s production is sour heavy oil which is the sole component of the field’s reserves. Oil is transported by pipeline primarily to purchasers in Casper, Wyoming. As a result of transportation differentials, the high sulfur content and low API gravity, this oil trades at a discount to WTI, averaging $9.60 lower for the year ended June 30, 2021, and $17.62 lower for the eight months ended June 30, 2020. Although we have the option of taking our production in-kind, we have elected to have the operator market our share of production. Our realized price is net of transportation and marketing costs.

On May 7, 2021, the Company acquired non-operated working interests in the Barnett Shale field in North Texas. The asset's production has various zones of wet and dry gas. The wet gas is gathered and transported by pipeline to a processing facility to process the wet gas into NGL components, oil condensate, and residue gas. Although we have the option of taking our production in-kind, we have elected to have the operator market our share of production.

The following table sets forth purchasers of our oil, natural gas, and NGL production for the years indicated:

	Year Ended June 30,	
Customer	2021	2020
Plains Marketing L.P. (Delhi field oil)	62 %	87 %
Merit Energy Company (Hamilton Dome field oil)	19 %	10 %
All others	19 %	3 %
Total	100 %	100 %

As the purchase of the Barnett Shale occurred on May 7, 2021, the Company expects purchases of our natural gas and NGL production from the Barnett Shale to represent a larger percentage of total sales in fiscal year 2022 and beyond. The loss of a purchaser at the Delhi field, Barnett Shale, or the Hamilton Dome field or disruption to pipeline transportation from these fields could adversely affect our net realized pricing and potentially our near-term production levels.

Market Conditions

Prices we receive for oil, natural gas, and NGLs are influenced by many factors that are beyond our control, the exact effect of which is difficult to predict. These factors include changes in supply and demand, market prices, government regulation, weather, and actions of major foreign producers.

Oil prices over the past few years have fluctuated widely and been extremely volatile. For example, average daily prices for WTI oil ranged from a high of $74 per barrel to a low of a negative $38 per barrel over our last two fiscal years. The price of oil per barrel dropped substantially in fiscal 2020 as a result of the impact of the COVID-19 pandemic and geopolitical factors but recovered to average above $66 per barrel during the fiscal fourth quarter of 2021. The severe drop in oil price during the pandemic and market share competition between OPEC+ members in the Spring of 2020 substantially and adversely impacted oil, gas, and NGL prices during the balance of 2020, thus impacted the trailing twelve-month commodity prices required for reserves and ceiling tests for asset carrying value which in turn led to substantial impairments during our first and second quarters of fiscal 2021. Worldwide factors such as global health pandemics, geopolitical, international trade disruptions and tariffs, macroeconomics, supply and demand, refining capacity, petrochemical production, and derivatives trading, among others, influence prices for oil, natural gas, and NGLs. Local factors also influence prices for oil, natural gas, and NGLs and include increasing or decreasing production trends, quality differences, regulation, and transportation issues unique to certain producing regions and reservoirs.

Competition

The oil and natural gas industry is highly competitive for prospects, acreage, and capital. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staff and greater capital resources. Competitors are national, regional, or local in scope and compete on the basis of financial resources, technical prowess or local knowledge. The principal competitive factors in our industry are expertise in given geographical areas and geologic systems and the ability to efficiently conduct operations, achieve technological advantages, identify and acquire economically producible reserves, and obtain capital at rates that allow economic investments.

Risk Management

Derivative instruments are occasionally utilized to hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales of future oil and natural gas production. We have designed a risk management policy to use derivative instruments from time to time during periods of extraordinary price volatility and when such instruments are needed to ensure the Company can meet its current dividend policy, fund its capital expenditures commitments, and maintain liquidity. We determine the duration of derivative positions to approximate the anticipated period of volatility and the percentage of our production to be hedged based on our view of current and future market conditions. We do not enter into derivative contracts for speculative trading purposes.

While there are many different types of derivatives available, we typically use fixed-price swaps and costless collars to attempt to manage price risk. The fixed-price swap agreements call for payments to, or receipts from, counterparties depending on whether the index price of oil or natural gas for the period is greater or less than the fixed price established for the period contracted under the fixed-price swap agreement. Costless collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All costless collar agreements provide for payments to counterparties if the settlement price under the agreement exceeds the ceiling and payments from the counterparties if the settlement price under the agreement is below the floor.

During fiscal 2020, we entered into NYMEX WTI oil swaps that covered approximately 42,000 barrels per month for the period of April 2020 through December 2020 at a fixed swap price of $32.00 per barrel. As of June 30, 2021, we did not have any open fixed-price swaps or costless collars. In the future, we may add additional swaps or other derivative positions covering a variable portion of our anticipated future production during subsequent periods.

It is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. For the year ended June 30, 2021, we did not post collateral under any of our derivative contracts as they are uncollateralized trades. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A and Note 18 to our consolidated financial statements in Item 8 for additional information.

Government Regulation

Numerous federal and state laws and regulations govern the oil and natural gas industry, including environmental laws and regulations. These laws and regulations are often changed in response to changes in the political or economic environment. Compliance with this evolving regulatory environment is often difficult and costly; substantial penalties may be incurred for noncompliance. To the best of our knowledge, we are in compliance with all federal and state-level laws and regulations applicable to our operations. The future annual capital cost of complying with the regulations applicable to our operations is uncertain and will be governed by several factors, including future changes to regulatory requirements which are unpredictable. We do not currently anticipate that continued and future compliance with existing laws and regulations will have a materially adverse effect on our consolidated financial position or results of operations.

See discussion captioned “Government regulation and liability for oil and gas operations and environmental matters may adversely affect our business and results of operations” in Item 1A.

Insurance

We maintain insurance on our oil and natural gas properties and operations for risks and in amounts customary in the industry. Such insurance includes general liability, excess liability, control of well, operators extra expense, casualty, fraud, and directors and officer's liability coverage. Not all losses are insured, and we retain certain risks of loss through deductibles, limits, and self-retentions. We do not carry lost profits coverage, and we do not have coverage for consequential damages.

Employment

At June 30, 2021, we had five full-time employees, not including contract personnel and outsourced service providers. None of the Company’s employees are currently represented by a union, and the Company believes that it has good relations with its employees. Our team is broadly experienced in oil and natural gas operations, development, acquisitions, and financing. We follow a strategy of outsourcing most of our property accounting, human resources, administrative, and other non-core functions.

Additional Information

We file Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other reports with the Securities and Exchange Commission (“SEC”). Our reports filed with the SEC are available free of charge to the general public through our website at www.evolutionpetroleum.com. These reports are accessible on our website as soon as reasonably practicable after being filed with, or furnished to, the SEC. This Annual Report on Form 10-K and our other filings can also be obtained by contacting: Corporate Secretary, 1155 Dairy Ashford Road, Suite 425, Houston, Texas 77079, or calling (713) 935-0122. These reports are also available at the SEC Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition, or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider to be immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our Company

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas significantly influences our revenue, profitability, access to capital, and future rate of growth. Oil and natural gas are commodities and their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, average daily prices for WTI oil ranged from a high of $74 per barrel to a low of a negative $38 per barrel, and Henry Hub natural gas prices ranged from a high of $23.86 to a low of $1.33 per MMBTU over our last two fiscal years. Historically, the markets for oil, natural gas, and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control, including, but not limited to the following:

- changes in global supply and demand for oil and natural gas, which has been negatively affected by concerns about the impact of COVID-19;
- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- actions of OPEC+ or other groups of oil producing nations;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries;
- governmental, scientific, and public concern over the threat of climate change arising from greenhouse emissions;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals of regional, domestic, and international transportation availability;
- weather conditions, natural disasters, and seasonal trends;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than 12-month) contracts at market-based prices. A decline in oil, natural gas, and NGL prices will reduce our cash flows, borrowing ability, the present value of our reserves, and our ability to develop future reserves. We may be unable to obtain needed capital or financing on satisfactory terms. Low oil, natural gas, and NGL prices may also reduce the amount of oil, natural gas, and NGL that we can produce economically, which could lead to a decline in our oil, natural gas and NGL reserves. At June 30, 2021, approximately 36% of our proved reserves are oil reserves, 35% are natural gas and 29% are NGL reserves. As such, we are heavily impacted by movements in natural gas and oil prices, the latter also influencing NGL prices. To the extent that we have not hedged our production with derivative contracts or fixed-price contracts, any significant and extended decline in oil, natural gas, and NGL prices may adversely affect our financial position.

Our revenues are concentrated in three assets and related declines in production or other events beyond our control could have a material adverse effect on our results of operations and financial results.

Our revenues come from our royalty, mineral, and working interests in the Delhi field in Louisiana, the Hamilton Dome field in Wyoming, and the Barnett Shale in Texas and thus our current revenues are concentrated from these fields. Any significant downturn in production, oil, natural gas, and NGL prices, or other events beyond our control which impact these fields could have a material adverse effect on our results of operations and financial results. We are not the operator of these fields, and our revenues and future growth are heavily dependent on the success of operations, which we do not control.

Operating results from oil and natural gas production may decline; we may be unable to acquire and develop the additional oil and natural gas reserves that are required in order to sustain our business operations.

In general, the volumes of production from oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we acquire additional properties containing proved reserves or conduct successful development activities, or both, our proved reserves will naturally decline. Our production is heavily dependent on our interests in EOR production that began during March 2010 in the Delhi field and our interests in the Hamilton Dome field in Wyoming and Barnett Shale in Texas. Environmental or operating problems or lack of extended future investment in any of these assets could cause our net production of oil, natural gas, and NGLs to decline significantly over time, which could have a material adverse effect on our financial condition. In fiscal 2021, our production was impacted by the operators of the Delhi and Hamilton Dome fields. Delhi production volumes were negatively impacted as a result of the financial strain Denbury was under and their lack of investment in projects in the field, including the delay of our Phase V, in addition to the purchased CO_2 line being shut in for repairs. In the Hamilton Dome field Merit temporarily shut in a portion of the production as it was uneconomic at the historically low prices. As of June 30, 2021, Merit has reactivated the inventory of shut-in wells capable of supporting their expenses and we continue to monitor their performance; however, there is no guarantee that prolonged periods of being shut-in or lack of investment would not negatively impact future production.

We have limited control over the activities on properties we do not operate.

Substantially all of our property interests are not operated by the Company and involve other third-party working interest owners. As a result, we have limited ability to influence or control the operation or future development of such properties, including compliance with environmental, safety, and other regulations, or the amount of capital expenditures that we will be required to fund with respect to such properties. Operators of these properties may act in ways that are not in our best interest. Moreover, we are dependent on the other working interest owners of such projects to fund their contractual share of the capital expenditures of such projects. These limitations and our dependence on the operator and other working interest owners for these projects could cause us to incur unexpected future costs, result in lower production, and materially and adversely affect our financial conditions and results of operations.

We are materially dependent upon our operators with respect to the successful operation of our principal assets, which consist of our interests in Delhi field, Hamilton Dome field, and the Barnett Shale. A materially negative change in any of our operator's financial condition could negatively affect operations (or timing thereof) in these assets, and consequently our income (or timing thereof) from these assets as well as the value of our interests in these assets.

Any significant downturn in production or other events beyond our control which impact our assets could have a material adverse effect on our results of operations and financial results (or timing thereof).

We are not the operator of the Delhi field. It is operated by a subsidiary of Denbury Inc. ("DNR"), an independent oil and gas company specializing in tertiary recovery with CO_2. Our revenues and future growth are thus heavily dependent on the success of operations which we do not control.

Further, our CO_2 - Enhanced Oil Recovery ("CO_2-EOR") project in the Delhi field requires significant amounts of CO_2 reserves and technical expertise, the sources of which have been committed by the operator. Additional capital remains to be invested to fully develop this project, further increase production, and maximize the value of this asset. The operator's failure to manage these and other technical, environmental, operating, strategic, financial, and logistical matters could cause ultimate enhanced recoveries from the planned CO_2 - EOR project to fall short of our expectations in volume and/or timing. Such occurrences could have a material adverse effect on us, and our results of operations and financial condition.

Our economic success is thus materially dependent upon the Delhi field operator's ability to: (i) deliver sufficient quantities of CO_2 from its reserves in the Jackson Dome source, (ii) secure its share of capital necessary to fund development and operating commitments with respect to the field, and (iii) successfully manage related technical, operating, environmental, strategic, and logistical risks, among other things.

In July 2020, Denbury announced that it had entered into a Restructuring Support Agreement with holders of 100% of revolving credit facility loans, approximately 67.2% of second lien notes and approximately 70.8% of convertible notes for a "pre-packaged" plan to eliminate $2.1 billion of bond debt and subsequently filed for voluntarily filed petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas. Denbury subsequently announced on September 3rd that its plan to eliminate $2.1 billion of its bond debt has been confirmed by the court which substantially reduced its debt, strengthened its balance sheet, and positioned Denbury to free up capital for investment in properties such as Delhi again.

We are not the operator of the Hamilton Dome field. It is operated by Merit, a private oil and natural gas company. Our revenues and future growth are thus heavily dependent on the success of operations which we do not control.

We are not the operator of the Barnett Shale assets. At the time of acquisition, approximately 90% of the wells in the Barnett Shale field were operated by Blackbeard, and the remaining 10% of wells were operated by seven other operators. Our revenues and future growth are thus heavily dependent on the success of operations which we do not control.

In May 2021, Blackbeard announced an agreement to sell its interest in the Barnett Shale assets to Diversified Energy. The transaction closed in July 2021, with Diversified Energy taking over as operator. Our revenues and future growth are heavily dependent on a smooth transition of operations from Blackbeard to Diversified Energy and the success of operations under Diversified Energy, which we do not control.

The types of resources we focus on have substantial operational risks.

Our business plan focuses on the acquisition and development of known resources in partially depleted reservoirs, naturally fractured, or low permeability reservoirs. Our Delhi and Hamilton Dome assets are productive from relatively shallow reservoirs, while our Barnett Shale assets produce from deeper reservoirs. Shallower reservoirs usually have lower pressure, which generally translates into lower reserve volumes in place. Deeper reservoirs have higher pressures and usually more reserve volumes, but capturing those reserves often comes at increased drilling and completion cost and risk. Low permeability reservoirs require more wells and substantial stimulation for development of commercial production. Naturally fractured reservoirs require penetration of sufficient un-depleted fractures to establish commercial production. Depleted reservoirs require successful application of newer technology to produce incremental reserves.

Our CO_2-EOR project in the Delhi field, operated by Denbury, requires significant amounts of CO_2 reserves, development capital, and technical expertise, the sources of which to date have been committed by the operator. Although initial CO_2 injection began at Delhi in November 2009, initial oil production response began in March 2010 and a large part of the capital budget has already been expended. Additional capital remains to be invested to fully develop the EOR project, further increase production, and maximize the value of the asset. The operator's failure to manage these and other technical, environmental, operating, strategic, financial, and logistical risks may ultimately cause enhanced recoveries from the planned CO_2-EOR project to fall short of our expectations in volume and/or timing. Such occurrences would have a material adverse effect on the Company, its results of operations and financial condition.

Oil and natural gas development, re-completion of wells from one reservoir to another reservoir, restoring wells to production, and drilling and completing new wells are speculative activities which involve numerous risks and substantial uncertain costs.

Our growth will be partially dependent upon the success of our future development program. Drilling for oil and natural gas and extracting NGLs and re-working existing wells involve numerous risks. The risk that no commercially productive oil or natural gas reservoirs will be encountered is paramount. The cost of drilling, completing, and operating wells is substantial and uncertain; drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors beyond our control, including, but not limited to:

- unexpected drilling conditions;
- pressure fluctuations or irregularities in reservoir formations;
- equipment failures or accidents;
- regulatory climate;
- inability to obtain or maintain leases on economic terms, where applicable;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Drilling or re-working is a highly speculative activity. Even when fully and correctly utilized, modern well completion and production techniques such as horizontal drilling or CO_2 injection, do not guarantee that we will find and produce oil and/or natural gas in our wells in economic quantities. Our future drilling activities may not be successful and, if unsuccessful, such failure would have an adverse effect on our future results of operations and financial condition. We cannot guarantee that our overall drilling success rate will not decline.

We may also identify and develop prospects through a number of methods, some of which may include horizontal drilling or tertiary injectants, and some of which may be unproven. The drilling and results for these prospects may be particularly uncertain. We cannot ensure that these projects can be successfully developed or that the wells discussed will, if drilled, encounter reservoirs of commercially productive oil or natural gas.

The loss of a large single purchaser of our oil and natural gas could reduce the competition of our production.

For the year ended June 30, 2021, one purchaser accounted for approximately 62% of our total oil revenues. We do not currently market our share of oil, natural gas, and NGLs production from the Delhi field, the Hamilton Dome field, or the Barnett Shale. Although we have the right to take our working interest production in-kind, we are currently accepting terms under the operators' agreements for the delivery and pricing of our oil, natural gas and NGLs. The loss of a large purchaser for our oil production could negatively impact the revenue we receive. We cannot guarantee that we could readily find other purchasers for our oil and natural gas production.

Our oil and natural gas reserves are only estimates and may prove to be inaccurate.

There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values. Our reserves are only estimates that may prove to be inaccurate because of these inherent uncertainties. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot always be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves depend upon a number of variable factors. These factors include historical production from the area compared with production from other comparable producing areas, assumptions concerning effects of regulations by governmental agencies, future oil and natural gas product prices, future operating costs, severance and excise taxes, development costs, work-over costs, and remedial costs. Some or all of these assumptions utilized in estimating reserve volumes may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of reserves, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected from reserves may vary substantially depending on the timing and different engineers preparing reserves estimates.

Accordingly, reserve estimates may be subject to downward or upward adjustments. Actual production, revenue, and expenditures with respect to our reserves will likely vary from estimates; such variances may be material. The information regarding discounted future net cash flows included in this report should not be considered as the current market value of the estimated oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the 12-month average 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, and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, increases or decreases in consumption, and changes in governmental regulations or taxation. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. Interest rates in effect vary from time to time based on risks associated with us or the oil and natural gas industry in general. The Standardized Measure does not necessarily correspond to market value.

Regulatory and accounting requirements may require substantial reductions in reporting proven reserves.

On a periodic basis, we review the carrying value of our oil and natural gas properties under the applicable rules of various regulatory agencies, including the SEC. Under the full cost method of accounting that we use, the after-tax carrying value of our oil and natural gas properties may not exceed the present value of estimated future net after-tax cash flows from proved reserves, discounted at 10%. Application of this “ceiling” test requires pricing future revenues at the previous 12-month average beginning-of-month price and requires a write-down of the carrying value for accounting purposes if the ceiling is exceeded. We may in the future be required to write down the carrying value of our oil and natural gas properties when oil and natural gas prices are depressed or unusually volatile. Whether we will be required to take such a charge will depend in part on the prices of oil and natural gas during the previous period and the effect of reserve additions or revisions and capital expenditures during such period. If a write-down is required, it would result in a current charge to our earnings but would not impact our current cash flow from operating activities. A large write-down could adversely affect our compliance with the current financial covenants under our credit facility, could limit our access to future borrowings under that facility, or require repayment of any amounts that might be outstanding at the time.

Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and NGLs, we have, and may in the future, enter into derivative arrangements for a portion of our oil, natural gas, and NGLs production. Derivative arrangements may include costless collars and fixed-price swaps. We have not historically designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our future derivative instruments. Derivative arrangements may also expose us to the risk of financial loss in some circumstances, including, but not limited to, if:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil, natural gas and NGLs and may expose us to cash margin requirements.

We may have difficulty managing future growth and the related demands on our resources and may have difficulty in achieving future growth.

Although we plan to experience growth through acquisitions and development activity, any such growth may place a significant strain on our financial, technical, operational, and administrative resources. Our ability to grow will depend upon a number of factors, including, but not limited to the following:

- our ability to identify and acquire new development projects;
- our ability to develop new and existing properties;
- our ability to continue to retain and attract skilled personnel;
- the results of our development program and acquisition efforts;
- the success of our technologies;
- hydrocarbon prices;
- drilling, completion, and equipment prices;
- our ability to successfully integrate new properties;
- our access to capital; and
- the Delhi field operator's ability to: (i) deliver sufficient quantities of CO2 from its reserves in the Jackson Dome, (ii) secure all of the development capital necessary to fund its and our cost interests, and further develop the Delhi field, such as advancement of Phase V development in the undeveloped eastern part of the field, (iii) successfully manage technical, operating, environmental, strategic and logistical development and operating risks, and (iv) maintain its own financial stability.

We cannot ensure that we will be able to successfully grow or manage any such growth.

Our operations may require significant amounts of capital and additional financing may be necessary in order for us to continue our exploitation activities.

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 acquisitions, exploitation, and development activities. Certain portions of our undeveloped leasehold acreage may be subject to expiration unless production is established. 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 current production. If our cash flow from operations is not sufficient to satisfy our capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available to us on favorable terms.

We will be subject to risks in connection with acquisitions, and the integration of significant acquisitions may be difficult and may involve unexpected costs or delays.

We periodically evaluate acquisitions of reserves, properties, prospects, leaseholds, and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including, but not limited to:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the seller's title to properties, which may be less than expected at closing; and
- potential environmental issues, litigation, and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not

necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Moreover, in the event of such an acquisition, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations, or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including, but not limited to:

- our management team's capacity could be challenged by the demands of evaluating, negotiating, integrating significant acquisitions, and strategic transactions in concert with the Company's ongoing business demands;
- the challenge and cost of integrating acquired operations, information management, other technology systems, and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volumes, cost savings from operating synergies, other benefits anticipated from an acquisition, or realize these benefits within the expected time frame.

Government regulation and liability for oil and natural gas operations and environmental matters may adversely affect our business and results of operations.

Oil and natural gas operations are subject to extensive federal, state, and local government regulations, which may be changed from time to time. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas from wells below actual production capacity in order to conserve supplies of oil and natural gas. There are federal, state, and local laws and regulations primarily relating to protection of human health and the environment applicable to the development, production, handling, storage, transportation, and disposal of oil and natural gas, by-products thereof, the emission of CO_2 or other greenhouse gases, and other substances and materials produced or used in connection with oil and natural gas operations. These laws and regulations may affect the costs, manner and feasibility of our operations and require us to make significant expenditures in order to comply. In addition, we may inherit liability for environmental damages, whether actual or not, caused by previous owners of property we purchase or lease or from nearby properties. As a result, failure to comply with these laws and regulations may result in substantial liabilities to third parties or governmental entities. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The implementation of new, or the modification of existing, laws or regulations could have a material adverse effect on us, such as diminishing the demand for our products through legislative enactment of proposed new penalties, fines and/or taxes on carbon that could have the effect of raising prices to the end user.

The risks arising out of concerns regarding the threat of climate change, including regulatory, political, litigation, and financial risks may adversely affect our business and results of operations.

The Company’s operations are subject to a number of risks arising out of concerns regarding the threat of climate change, including regulatory, political, litigation, and financial risks, that could result in increased operating costs and costs of compliance, limit the areas in which oil and natural gas production may occur and reduce the demand for oil and natural gas.

The threat of climate change continues to attract considerable attention. Numerous initiatives have been proposed and more are expected to come that focus on monitoring and limiting existing sources of greenhouse gas emissions as well as to restrict or eliminate emissions from new sources. As a result, the Company is subject to numerous risks associated with the production and processing of fossil fuels and emission of greenhouse gas.

Governmental, scientific, and public concern over the threat of climate change arising from greenhouse emissions has resulted in increasing political risks in the United States. Proposals to ban hydraulic fracturing of oil and natural gas wells and ban new leases for production of minerals on federal properties, including onshore lands and offshore waters have already been made. Other actions that could be pursued may include more restrictive requirements for drilling or construction permits, the reversal of the United States’ withdrawal from the Paris Agreement in November 2020, and reinstatement of the ban on oil exports. Litigation risks are also increasing as a number of suits against oil and natural gas exploration and production companies have been brought in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects.

There are also financial risks for the energy industry as it may become more difficult to access the capital markets as the threat of climate change may impact decisions made by potential investors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Limitation of investments in and financings for the energy industry could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Our business could be negatively affected by security threats. A cyber-attack or similar incident could occur and result in information theft, data corruption, operational disruption, damage to our reputation, and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing, and financial activities. We depend on digital technology to estimate quantities of oil and natural gas reserves, manage operations, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Our technologies, systems, networks, seismic data, reserves information, or other proprietary information, and those of our operators, vendors, suppliers, customers, and other business partners may become the target of cyber-attacks or information security breaches. Cyber-attacks or information security breaches could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could otherwise lead to the disruption of our business operations or other operational disruptions in our exploration or production operations. Cyber-attacks are becoming more sophisticated and certain cyber incidents, such as surveillance, may remain undetected for an extended period and could lead to disruptions in critical systems or the unauthorized release of confidential or otherwise protected information. These events could lead to financial losses from remedial actions, loss of business, disruption of operations, damage to our reputation, or potential liability. Also, computers control nearly all of the oil and natural gas distribution systems in the United States of America and abroad. Computers are necessary to transport our oil and natural gas production to market. A cyber-attack directed at oil and natural gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions. Cyber incidents have increased, and the United States of America government has issued warnings indicating that energy assets may be specific targets of cybersecurity threats. Our systems and insurance coverage for protecting against cybersecurity risks may not be sufficient. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Our insurance may not protect us against all of the operating risks to which our business is exposed.

The oil and natural gas business involves numerous operating hazards such as well blowouts, mechanical failures, explosions, uncontrollable flows of oil, natural gas, or well fluids, fires, formations with abnormal pressures, hurricanes, flooding, pollution, releases of toxic gas, and other environmental hazards and risks, which can result in (i) damage to or destruction of wells and/or production facilities, (ii) damage to or destruction of formations, (iii) injury to persons, (iv) loss of life, or (v) damage to property, the environment or natural resources. While we carry general liability, control of well, and operator's extra expense coverage typical in our industry, we are not fully insured against all risks incidental to our business. Environmental events similar to that experienced in the Delhi field in June 2013 could defer revenue, increase operating costs, and/or increase maintenance and repair capital expenditures.

The loss of key personnel could adversely affect us.

We depend to a large extent on the services of certain key management personnel, including our executive officers. The loss of one or more key personnel could have a material adverse effect on our operations. In particular, our future success is dependent upon the abilities of Robert Herlin, our Chairman of the Board, Jason Brown, our President and Chief Executive Officer, and Ryan Stash, Senior Vice President, Chief Financial Officer, and Treasurer, to source, evaluate, and close deals, raise capital, and oversee our development activities and operations. Presently, the Company is not a beneficiary of any key man life insurance.

Oil field service and materials prices may increase, and the availability of such services and materials may be inadequate to meet our needs.

Our business plan to develop or redevelop oil and natural gas resources requires third-party oilfield service vendors and various material providers, which we do not control. We also rely on third-party carriers for the transportation and distribution of our oil and natural gas production. As our production increases, so does our need for such services and materials. Generally, we do not have long-term agreements with our service and materials providers. Accordingly, there is a risk that any of our service providers could discontinue servicing our oil and natural gas fields for any reason or we may not be able to source the materials we need. Any delay in locating, establishing relationships, and training our sources could result in production shortages and

maintenance problems, resulting in loss of revenue to us. In addition, if costs for such services and materials increase, it may render certain or all of our projects uneconomic, as compared to the earlier prices we may have assumed when deciding to redevelop newly purchased or existing properties. Further adverse economic outcomes may result from the long lead times often necessary to execute and complete our redevelopment plans.

We cannot market the oil and natural gas that we produce without the assistance of third-parties.

The marketability of the oil and natural gas that we produce depends upon the proximity of our reserves to, and the capacity of, facilities and third-party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities necessary to make the products marketable for end use. The unavailability or lack of capacity of such services and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. A shut-in, delay, or discontinuance could adversely affect our financial condition.

We face strong competition from larger oil and gas companies.

Our competitors include major integrated oil and natural gas companies, numerous larger independent oil and natural gas companies, individuals, and drilling and income programs. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources. We may not be able to successfully conduct our operations, evaluate and select suitable properties, or consummate transactions in this highly competitive environment. Specifically, these larger competitors may be able to pay more for development projects and productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may be able to expend greater resources on hiring contract service providers, obtaining oilfield equipment, and acquiring the existing and changing technologies that we believe are, and will be, increasingly important to attaining success in our industry.

We have been, and in the future may become, involved in legal proceedings related to our properties or operations and, as a result, may incur substantial costs in connection with those proceedings.

From time to time we may be a defendant or plaintiff in various lawsuits. The nature of our operations exposes us to further possible litigation claims in the future. There is risk that any matter in litigation could be decided unfavorably against us regardless of our belief, opinion, and position, which could have a material adverse effect on our financial condition, results of operations, and cash flow. Litigation can be very costly, and the costs associated with defending litigation could also have a material adverse effect on our financial condition. Adverse litigation decisions or rulings may damage our business reputation.

Ownership of our oil, gas, and mineral production depends on good title to our property.

Good and clear title to our oil, natural gas, and mineral properties is important to our business. Although title reviews will generally be conducted prior to the purchase of most oil, natural gas, and mineral producing properties or the commencement of drilling wells, such reviews do not assure that an unforeseen defect in the chain of title will not arise to defeat our claim. This could result in a reduction or elimination of the revenue received by us from such properties.

Events outside of our control, including a pandemic or broad outbreak of an infectious disease, such as the ongoing global outbreak of a novel strain of the coronavirus identified in late 2019 ("COVID-19") and subsequent variants, may materially adversely affect our business.

We face risks related to pandemics, outbreaks, or other public health events that are outside of our control and could significantly disrupt our operations and adversely affect out financial condition. In December 2019, a novel strain of a coronavirus, COVID-19, was identified in Wuhan, China. This virus continues to have a material impact globally. These and other actions could, among other things, impact the ability of our employees and contractors to perform their duties, cause increased technology and security risk due to extended and company-wide telecommuting, and lead to disruptions in our permitting activities and critical business relationships. Additionally, the COVID-19 outbreak and governmental restrictions have significantly impacted economic activity and markets and have dramatically reduced current and anticipated demand for oil and natural gas, adversely impacting the prices we receive for our production. The severity and duration of the current COVID-19 outbreak and the subsequent variants in addition to the potential for future outbreaks are uncertain and difficult to predict.

The extent to which COVID-19 impacts our business will depend on future developments, which are highly uncertain and cannot be predicted, including new information which may emerge concerning the severity of the coronavirus and the actions to contain the coronavirus or treat its impact, among others. We are unable to predict the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments, including the length of time that the pandemic continues, its ongoing effect on the demand for oil and natural gas and the response of the overall economy and the financial markets after governmental restrictions are eased.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, declining oil and natural gas prices, geopolitical issues, the availability and cost of credit, the United States of America mortgage market, uncertainties with regard to European sovereign debt, the slowdown in economic growth in large emerging and developing markets, such as China, regional or worldwide increases in tariffs or other trade restrictions, and other issues have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on domestic and international financial markets and commodity prices. If uncertain or poor economic, business, or industry conditions in the United States of America or abroad remain prolonged, demand for petroleum products could diminish or stagnate, and production costs could increase. These situations could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers', and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Risks Associated with Our Stock

Our stock price has been and may continue to be volatile.

Our common stock has relatively low trading volume and the market price has been, and is likely to continue to be, volatile. For example, during the fiscal year ended June 30, 2021, our stock price as traded on the NYSE American ranged from $2.75 to $5.15. The variance in our stock price makes it difficult to forecast with certainty the stock price at which an investor may be able to buy or sell shares of our common stock. The market price for our common stock could be subject to fluctuations as a result of factors that are out of our control, such as:

- actual or anticipated variations in our results of operations;
- naked short selling of our common stock and stock price manipulation;
- changes or fluctuations in the commodity prices of oil and natural gas;
- general conditions and trends in the oil and natural gas industry;
- redemption demands on institutional funds that hold our stock; and
- general economic, political and market conditions.

Significant ownership of our common stock is concentrated in a small number of shareholders who may be able to affect the outcome of the election of our directors and all other matters submitted to our stockholders for approval.

As of June 30, 2021 our executive officers and directors, in the aggregate, beneficially owned approximately 2.7 million shares, or approximately 8.0% of our beneficial common stock base. Blackrock Fund Advisors, et al controlled approximately 2.0 million shares or approximately 6.1% of our outstanding common stock, Arrowmark Colorado Holdings, LLC controlled approximately 2.0 million shares or approximately 6.1% of our outstanding common stock and Renaissance Technologies, LLC controlled approximately 2.2 million shares or approximately 6.5% of our outstanding common stock. As a result, any of these holders could potentially exercise significant influence over matters submitted to our stockholders for approval (including the election and removal of directors and any merger, consolidation or sale of all or substantially all of our assets). This concentration of ownership may have the effect of delaying, deferring or preventing a change in control of our company, impede a merger, consolidation, takeover, or other business combination involving our company or discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company, which in turn could have an adverse effect on the market price of our common stock.

The market for our common stock is limited and may not provide adequate liquidity.

Our common stock trades on the NYSE American stock exchange. Trading volume in our common stock is relatively low compared to larger companies. During the fiscal year ended June 30, 2021, the daily trading volume in our common stock ranged from a low of 38,100 shares to a high of 4,596,300 shares, with average daily trading volume of 169,054 shares compared to average daily volume of 155,691 in fiscal 2020. Our holders may find it more difficult to sell their shares, should they desire to do so, based on the trading volume and price of our stock at that time relative to the quantity of shares to be sold.

If securities or industry analysts do not publish research reports about our business, or if they downgrade our stock, the price of our common stock could decline.

Small, relatively unknown companies can achieve visibility in the trading market through research and reports that industry or securities analysts publish. To our knowledge, three independent analysts cover our company. The limited number of published reports by independent securities analysts could limit the interest in our common stock and negatively affect our stock price. We do not have any control over the research and reports these analysts publish or whether they will be published at all. If any analyst who does cover us downgrades our stock, our stock price could decline. If any analyst ceases coverage of our company or fails to regularly publish reports on us, we could lose visibility in the financial markets, which in turn could cause our stock price to decline.

The issuance of additional common stock and preferred stock could dilute existing stockholders.

We currently have in place an effective registration statement which allows the company to publicly issue up to $500 million of additional securities, including debt, common stock, preferred stock, and warrants. At any time we may make private offerings of our securities. The shelf registration is intended to provide greater flexibility to the company in financing growth or changing our capital structure. We are authorized to issue up to 100,000,000 shares of common stock. To the extent of such authorization, our board of directors has the ability, without seeking stockholder approval, to issue additional shares of common stock in the future for such consideration as our board may consider sufficient. The issuance of additional common stock in the future would reduce the proportionate ownership and voting power of the common stock now outstanding. We are also authorized to issue up to 5,000,000 shares of preferred stock, the rights and preferences of which may be designated in series by our Board of Directors. Such designation of any new series of preferred stock may be made without stockholder approval and could create additional securities which would have dividend and liquidation preferences over the common stock now outstanding. Preferred stockholders could adversely affect the rights of holders of common stock by:

- exercising voting, redemption, and conversion rights to the detriment of the holders of common stock;
- receiving preferences over the holders of common stock regarding our surplus funds in the event of our dissolution, liquidation, or the payment of dividends to preferred stockholders;
- delaying, deferring, or preventing a change in control of our company; and
- discouraging bids for our common stock.

Payment of dividends on our common stock has been in the past, and could be in the future, reduced or eliminated.

Our Board of Directors declared cash dividends on our common stock for the first time in December 2013 and we have declared and paid quarterly cash dividends since that time. However, there is no certainty that dividends will be declared by the Board of Directors in the future. Any payment of cash dividends on our common stock in the future will be dependent upon the amount of funds legally available, our earnings, if any, our financial condition, our business plan, restrictions contained in current or future debt instruments, contractual covenants or arrangements we may enter into, our anticipated capital requirements, and other factors that our Board of Directors may think are relevant. Although it is our intent to maintain a steady dividend for our shareholders, there is no guarantee that we will be able to do so. For example, during the 3rd quarter of fiscal 2020, we reduced our quarterly dividend from $0.10 per common share to $0.025. The quarterly dividend was $0.05 for the fourth quarter of fiscal 2021 as a result of an improving financial and industry outlook. There is no guarantee that we will be able or choose to continue to pay cash dividends on our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in Item 1 above and in Note 6 to our consolidated financial statements in Item 8, which information is incorporated herein by reference.

Item 3. Legal Proceedings

See Note 16 to our consolidated financial statements in Item 8 for a description of any legal proceedings, which is incorporated herein by reference.

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

Common Stock

Our common stock is currently traded on the NYSE American stock exchange under the ticker symbol “EPM”. The following table shows, for each quarter of the fiscal years ended June 30, 2021 and 2020, the high and low sales prices for EPM as reported by the NYSE American stock exchange.

NYSE American: EPM

2021:	**High**	**Low**
Fourth quarter ended June 30, 2021	$ 5.15	$ 3.13
Third quarter ended March 31, 2021	$ 4.35	$ 2.75
Second quarter ended December 31, 2020	$ 3.15	$ 2.14
First quarter ended September 30, 2020	$ 2.93	$ 2.24

2020:	**High**	**Low**
Fourth quarter ended June 30, 2020	$ 3.20	$ 2.23
Third quarter ended March 31, 2020	$ 5.62	$ 2.16
Second quarter ended December 31, 2019	$ 5.86	$ 5.08
First quarter ended September 30, 2019	$ 7.05	$ 5.55

Shares Outstanding and Holders

As of June 30, 2021, there were 33,514,952 shares of common stock issued and outstanding. As of September 1, 2021, there were approximately 216 registered shareholders of our common stock.

Dividends

We began paying cash quarterly dividends on our common stock in December 2013. Over the last two fiscal years, the Company made the following cash dividends per share:

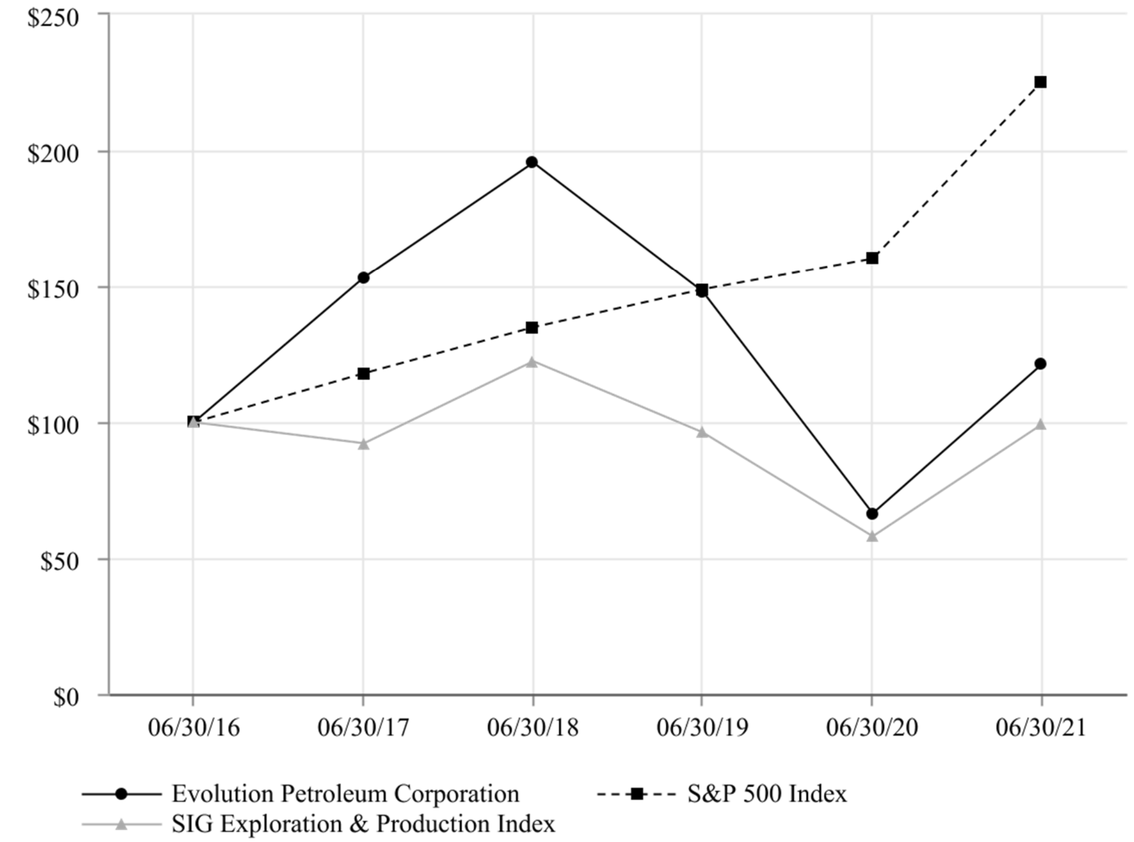
	Years Ended June 30,	
	2021	**2020**
Fourth quarter ended June 30,	$0.050	$0.025
Third quarter ended March 31,	$0.030	$0.100
Second quarter ended December 31,	$0.025	$0.100
First quarter ended September 30,	$0.025	$0.100

As of June 30, 2021, we have paid 31 consecutive quarterly dividends on our common stock. In September 2021, the Company declared a $0.075 per share dividend payable on September 30, 2021. Any future determination with regard to the payment of dividends will be at the discretion of the Board of Directors and will be dependent upon our future earnings, financial condition, results of operations, applicable dividend restrictions, capital requirements, and other factors deemed relevant by the Board of Directors.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our Common Stock over the period from June 30, 2016 to June 30, 2021 with the cumulative total return of the S&P 500 Index and the S&P Oil & Gas Exploration and Production Index of publicly traded companies over the same period. The graph assumes that $100 was invested on June 30, 2016 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any. The graph is presented in accordance with requirements of

the SEC. Shareholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.



Securities Authorized For Issuance Under Equity Compensation Plans

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)**	**Weighted-average exercise price of outstanding Options, warrants and rights (b)**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(1)**
Equity compensation plans approved by security holders:			
Outstanding options	—	$ —	
Outstanding contingent rights to shares	323,080 (1)	—	
Total	323,080	$ —	2,206,294
Equity compensation plans not approved by security holders	—	—	—
Total	**323,080**	**$ —**	**2,206,294**

(1) In December 2016, the Company adopted the Equity Incentive Plan (the “2016 Plan”), which authorized the issuance of 1,100,000 shares of common stock. On December 9, 2020, an amendment to the 2016 Plan was approved by our stockholders that increased the number of shares available for issuance by 2,500,000 shares. As of June 30, 2021, the Company has granted 1,444,230 awards under the 2016 Plan and 2,206,294 shares of common stock remain available for future grants.

Issuer Purchases of Equity Securities

During the fourth quarter ended June 30, 2021, the Company did not purchase any common stock in the open market under the previously announced share repurchase program and no shares of common stock were surrendered by its employees to pay their share of payroll taxes arising from vesting of restricted stock.

Item 6. Selected Financial Data

The selected consolidated financial data, set forth below should be read in conjunction with Item 7 and Item 8.

	June 30,				
	2021	2020	2019	2018	2017
Income Statement Data					
Revenues	$ 32,702,354	$ 29,599,296	$ 43,229,621	$ 40,773,527	$ 34,253,681
Lease operating costs	16,587,052	13,505,502	14,266,784	11,685,817	10,604,594
Depreciation, depletion and amortization	5,166,626	5,761,498	6,253,083	6,102,288	5,779,069
Net loss on derivative contracts	614,645	1,383,204	—	—	—
General and administrative expenses	6,754,532	5,259,659	5,072,931	6,773,781	4,985,408
Impairment of proved property	24,792,079	—	—	—	—
Impairment of Well Lift Inc. - related assets	146,051	—	—	—	—
Restructuring charges	—	—	—	—	4,488
Income (loss) from operations	(21,358,631)	3,689,433	17,636,823	16,211,641	12,880,122
Other income (expense)	(63,564)	66,643	1,222,604	(25,126)	4,855
Income tax provision (benefit)	(4,984,261)	(2,180,996)	3,482,361	(3,431,969)	4,840,664
Net income (loss) attributable to the Company	(16,437,934)	5,937,072	15,377,066	19,618,484	8,044,313
Dividends on preferred stock	—	—	—	—	250,990
Deemed dividend on preferred shares called for redemption	—	—	—	—	1,002,440
Net income (loss) attributable to common shareholders	$ (16,437,934)	$ 5,937,072	$ 15,377,066	$ 19,618,484	$ 6,790,883
Earnings per common share:					
Basic	$ (0.49)	$ 0.18	$ 0.46	$ 0.59	$ 0.21
Diluted	$ (0.49)	$ 0.18	$ 0.46	$ 0.59	$ 0.21

	June 30, 2021	June 30, 2020	June 30, 2019	June 30, 2018	June 30, 2017
Balance Sheet Data					
Total current assets	$ 18,108,374	$ 25,316,698	$ 35,178,927	$ 32,147,556	$ 26,142,527
Total assets	76,705,662	92,138,236	95,761,844	93,662,544	88,268,668
Total current liabilities	6,594,160	4,278,859	2,752,694	4,430,214	2,718,894
Total liabilities	22,110,859	18,013,754	15,635,986	16,373,065	19,798,813
Total stockholders' equity	54,594,803	74,124,482	80,125,858	77,289,479	68,469,855
Number of common shares outstanding	33,514,952	32,956,496	33,183,730	33,080,543	33,087,308
Working capital	11,514,214	21,037,839	32,426,233	27,717,342	23,423,633
Common stock dividends	4,342,082	10,740,754	13,272,058	11,594,541	8,432,435

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

Executive Overview

General

Evolution Petroleum Corporation is an oil and natural gas company focused on delivering a sustainable dividend yield to its stockholders through the ownership, management, and development of oil and natural gas properties. In support of that objective, the Company's long-term goal is to build a diversified portfolio of oil and natural gas assets primarily through acquisitions, while seeking opportunities to maintain and increase production through selective development, production enhancements, and other exploitation efforts on its properties.

Our producing assets consist of our interests in the Delhi Holt-Bryant Unit in the Delhi field in Northeast Louisiana, a CO_2 enhanced oil recovery project, our interests in the Hamilton Dome field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir, our interests in the Barnett Shale located in North Texas, a natural gas producing shale reservoir, and overriding royalty interests in two onshore central Texas wells.

Our interests in the Delhi field consist of a 23.9% working interest, with an associated 19.0% revenue interest and separate overriding royalty and mineral interests of 7.2% yielding a total net revenue interest of 26.2%. The field is operated by Denbury, a subsidiary of Denbury, Inc.

On November 1, 2019, the Company acquired mineral interests in the Hamilton Dome field consisting of a 23.5% working interest, with an associated 19.7% revenue interest (inclusive of a small overriding royalty interest). The field is operated by Merit, a private oil and natural gas company, who owns the vast majority of the remaining working interest in Hamilton Dome field. Our acquired interest in this field aligns with the Company's strategy of adding long-lived, low decline reserves expected to be supportive of our dividend over the long-term.

On May 7, 2021, the Company acquired non-operated working interests in the Barnett Shale consisting of approximately 21,000 net acres held by production across nine North Texas counties in the Barnett Shale. The acreage has an average working interest of 17.3% and associated average revenue interest of 14.2%. At the time of the Barnett Shale acquisition, approximately 90% of the wells acquired were operated by Blackbeard, while the remaining 10% were operated by the seven other operators. After the close of the Barnett Shale Acquisition, Blackbeard announced the sale of its interest to Diversified Energy, which closed in July of 2021. At present, Blackbeard is still the operator of the assets under a transition services agreement with Diversified Energy. However, after the transition, Diversified Energy will take over operations of the assets.

<u>Highlights for our Fiscal Year 2021 and Operations Update</u>

- Closed the Barnett Shale Acquisition on May 7, 2021 which included total proved reserves of 13.1 MMBOE as of June 30, 2021 as estimated by DeGolyer & MacNaughton (“D&M”), an independent reservoir engineering firm.
- Returned to shareholders $4.3 million in cash dividends in fiscal 2021. The Company has paid out to shareholders more than $74.5 million in cash dividends since inception of the dividend program in December 2013.
- Generated $3.7 million in operating income before impairments.
- Funded our fiscal year operations, capital expenditures, and dividends out of operating cash flow.
- Proved oil equivalent reserves at June 30, 2021 were 23.4 MMBOE, a 129% increase from the previous year primarily due to the acquisition of interests in the Barnett Shale in May 2021.
- We completed the NYMEX WTI oil swaps entered into during fiscal year 2020, and we have not entered into any new oil and gas derivatives as of June 30, 2021.
- Denbury, whose subsidiary operates the Delhi Field, emerged from bankruptcy on September 18, 2020 and returned to conformance projects with a refreshed capital budget after a period of no conformance spending.

Oil & Natural Gas Liquids Reserves (based on SEC NYMEX WTI oil price of $49.72 per barrel)

Proved oil equivalent reserves at June 30, 2021 were 23.4 MMBOE, a 129% increase from the previous year primarily due to the acquisition of interests in the Barnett Shale in May 2021. The Standardized Measure for proved reserves increased 40% to $87.6 million, primarily due to the acquisition of interests in the Barnett Shale and an increase in the SEC mandated trailing twelve month average first day of the month net oil price from $46.37 per barrel of oil and $9.00 per barrel of natural gas liquids (we did not have natural gas reserves as of June 30, 2020) at June 30, 2020 to $49.72 per barrel of oil, $19.81 per barrel of natural gas liquids and $2.46 per MMBtu of natural gas at June 30, 2021. Our proved reserves consist of 36% oil, 29% natural gas liquids and 35% natural gas, 92% are classified as proved developed producing and 8% are proved undeveloped.

The following table is a summary of our proved reserves as of June 30, 2021 and 2020:

	Proved Reserves		
	2021	**2020**	**Change**
Reserves MMBOE	23.4	10.2	129 %
% Developed	92 %	82 %	12 %
Liquids %	65 %	100 %	(35)%
Standardized Measure ($MM)	$ 87.6	$ 62.5	40 %

Additional property and project information is included under Item 1 and in Note 6 and Note 20 to our consolidated financial statements in Item 8, and in Exhibit 99.1 of this Form 10-K.

Delhi Field

At June 30, 2021, we had total net proved reserves of 8.5 MMBOE compared to the prior year's 8.7 MMBOE, or a 3% decline in proved oil reserves. Fiscal year 2021 production of 0.5 MMBOE was partially offset by 0.3 MMBOE positive revisions primarily due to price increases.

Gross production at Delhi in the fourth quarter of fiscal 2021 was 5.1 MBOEPD, a 2% increase compared to 5.0 MBOEPD in the third fiscal quarter. Oil production was 4.1 MBOPD, which was flat compared to the third fiscal quarter’s 4.1 MBOPD. NGL production in the fourth quarter was 1.0 MBOEPD, an increase of 9% compared to third fiscal quarter's 0.9 MBOEPD. Annual oil production was significantly impacted by cessation of CO_2 purchases when the CO_2 purchase pipeline, upstream of the Delhi field, was shut-in for repairs in late February until October 2020 combined with constrained purchase volumes after the pipeline was returned to service. The loss of CO_2 purchases, coupled with the decline in oil prices and bankruptcy filing, led to the operator electing to freeze non-essential capital projects through the end of calendar year 2020. During the fourth quarter of fiscal 2021, the operator resumed limited capital conformance projects within the field. We continue to monitor and evaluate the effectiveness of these projects.

The average oil price realized by Evolution at the Delhi field during the fourth quarter of fiscal 2021 was $64.68 compared to $56.02 during the previous quarter, an increase of 15%. The average NGL price realized by Evolution at the Delhi field during the fourth quarter of fiscal 2021 was $28.69 per barrel compared to $26.00 during the previous quarter, an increase of 10%. The increase was attributable to the broad recovery of commodity prices in fiscal fourth quarter. The uncertain demand outlook due to the ongoing COVID-19 pandemic has resulted in continued volatility in benchmark oil prices, with prices ranging from a low of a price of $58.73 per Bbl to a high of $74.21 per Bbl during our fiscal fourth quarter.

We historically have benefited from the premium that the Delhi field oil receives selling under Louisiana Light Sweet (“LLS”) pricing, as compared to the more widely known West Texas Intermediate (“WTI”) price. The LLS index correlates more closely to the Brent Crude oil price index (“Brent”) and, as such typically trades at a premium to the WTI index. Among other factors, the impacts of the COVID-19 pandemic caused global demand reduction and resulted in the Brent to WTI price spread to tighten, thus also resulting in a lower LLS to WTI price spread. In the fiscal fourth quarter 2021, the Delhi field realized a discount to WTI of $1.51, after deducting marketing and transportation costs. Oil produced from the Delhi field is shipped to market directly by pipeline, the most cost-effective means of transportation from the field. In addition, our received NGL price for royalty production varies because our royalty interests are burdened by a capital recovery charge, which is mostly offset by our working interest share that is reflected as a reduction in lease operating expense.

Our overall lifting costs per BOE for the year were $18.80 per BOE, which increased 14% from $16.50 per BOE in the prior year. Gross CO_2 purchase volume rates for fiscal 2021 averaged 49.1 MMcf per day, compared to 51.9 MMcf per day in the prior year, a 5% decrease primarily due to the Delhi CO_2 purchase pipeline shut-in for repairs. This decrease together with a 8% lower price per MCF resulted in a 13% decrease in CO_2 cost compared to the prior year. Our cost of purchased CO_2, the largest single component of operating costs at Delhi, is directly tied to the price of oil sold from the field. Other lease operating

expenses for fiscal 2021 decreased 10% compared to the prior year, primarily due to lower fuel gas, parts and workover expenses. The decrease in CO_2 cost and other lease operating expenses, paired with a decrease in production of 22% for the current year, resulted in the increase in lifting costs per BOE.

For fiscal 2021, our gross NGL production was 1.0 MBOEPD, which sold at an average price of $21.36 per barrel, compared to prior year gross production of 1.1 MBOEPD for which we realized $9.59 per barrel. In addition, the previously mentioned the capital recovery charge affects the NGL price in that if oil prices are below a realized NGL price of $60, the Company's royalty interests in Delhi do not benefit from NGL sales, partially offset by a reduction in the plant operating costs representing our working interest share of the cost recovery fee. This contributed to a lower price per barrel in the prior fiscal year, and the higher price per barrel in fiscal year 2021. Production from the NGL plant is transported by truck to a processing plant in East Texas, and therefore bears a material transportation charge. Our current mix of products is very rich, containing higher value NGLs, such as pentanes and butane. Historically, NGL demand has had a seasonal pattern with prices tending to be higher in the cooler months of the year. Accordingly, the relationship between NGL prices and WTI has fluctuated over time and we expect such volatility to continue in the future.

The NGL plant includes a gas turbine driven generator that converts methane and part of the ethane processed by the plant into electricity. This turbine generates power primarily for the NGL plant and supplies excess power to the CO_2 recycle facility. The NGL plant is accomplishing its primary objective of removing the lighter, smaller chain hydrocarbons, thereby increasing the purity of the CO_2 recycle stream and improving the efficiency of the CO_2 flood throughout the field. Over time, the NGL plant is expected to increase and enhance the recovery of oil in the field. The NGL plant is not only providing feedstock to power the electric turbine, it is also producing significant quantities of higher value NGLs to sell to market.

Remaining estimated capital expenditures for our proved undeveloped reserves amount to approximately $6.44 per BOE of PUD reserves for Phase V. Looking forward, the timing of plans for continued development of the eastern part of the Delhi field are dependent on the operator’s schedule for capital allocation within their portfolio but is projected to occur in the next few years. Development of unquantified volumes is dependent upon the timing of excess capacity within the processing plant and oil price. Over the past decade, we, along with the operator, have invested significant resources and capital demonstrating our commitment to the development of the Delhi field and believe that we will collectively continue to do so.

Hamilton Dome

At June 30, 2021, we had total net proved reserves of 1.9 MMBOE, entirely comprised of oil, compared to prior year net proved reserves of 1.5 MMBOE. The positive revision of 0.4 MMBOE, or 26%, in proved oil reserves is primarily related to improved oil pricing, decreased expenses and restoration of shut-in production from the global pandemic.

Gross oil production at Hamilton Dome in the fourth quarter of fiscal 2021 was 2,035 BOPD, a 3% increase compared to 1,985 BOPD in the third fiscal quarter due to the operator restoring previously shut-in production and maintenance within the field. There were limited capital expenditures in the field during fiscal 2021 due primarily to the decrease in oil prices. Most projects in the field focused on maintenance or restoring shut-in production.

The average oil price realized by Evolution at Hamilton Dome during the fourth quarter was $55.93 compared to $46.61 during the previous quarter, an increase of 20% attributable to the recovery in commodity prices in the fiscal fourth quarter. Production from this field is transported by pipeline to customers and is priced on the Western Canadian Select index, which generally trades at a discount to WTI. In the fourth quarter, our realized price reflected a $7.58 per barrel discount from the WTI price. For fiscal 2021, realized oil price averaged $42.28 compared to $29.19 for the prior year. For this fiscal year, our lifting costs at Hamilton Dome averaged $28.57 per barrel.

Barnett Shale

At June 30, 2021, we had total net proved reserves of 13.1 MMBOE, comprised of 62% natural gas, 37% natural gas liquids, and 1% oil as estimated by our independent petroleum engineering firm D&M. The Barnett Shale asset was acquired on May 7, 2021.

Blackbeard, the primary Barnett Shale operator has yet to formalize a budget, as they are currently under a transition services agreement with Diversified Energy following the sale of their interests to Diversified Energy in July 2021. Diversified Energy has expressed interest in identifying and performing remedial workovers to maintain and restore production.

Impact of Geopolitical Factors and the COVID-19 Pandemic

On March 11, 2020, the World Health Organization declared COVID-19 a pandemic, and on March 13, 2020, the United States of America declared a national emergency with respect to COVID-19. The virus has continued to spread in the United States of America and abroad. National, state, and local authorities continue to recommend social distancing, imposed quarantine and isolation measures, as well as periodic business closures on large portions of the population as the Delta variant of COVID-19 has emerged in the current fiscal year. These measures, while intended to protect human life, are expected to have continued impacts on domestic and foreign economies, potentially resulting in the volatility of commodity prices. The effectiveness of economic stabilization efforts, including government payments to affected citizens and industries, is uncertain.

Currently, all of the Company's property interests are not operated by the Company and involve other third-party working interest owners. As a result, the Company has limited ability to influence or control the operation or future development of such properties. In light of the current price and economic environment, the Company continues to be proactive with its third-party operators to review spending and alter plans as appropriate.

The Company is focused on maintaining its operations and system of controls remotely and has implemented its business continuity plans in order to allow its employees to securely work from home. The Company was able to transition the operation of its business with minimal disruption and to maintain its system of internal controls and procedures.

Liquidity and Capital Resources

At June 30, 2021, we had $5.3 million in cash and cash equivalents, primarily impacted by the $18.3 million purchase (net of preliminary purchase price adjustments and $2.8 million in non-cash asset retirement obligations) of certain mineral interests in the Barnett Shale in May 2021, compared to $19.7 million of cash and cash equivalents at June 30, 2020.

In addition, the Company has a senior secured reserve-based credit facility (the "Facility") with a maximum capacity of $50 million subject to a borrowing base determined by the lender based on the value of our oil and gas properties. The Facility had a $30 million borrowing base, with $4 million drawn as of June 30, 2021. The borrowing base does not yet include any portion of the Barnett Shale properties. There are $4 million in borrowings outstanding under the Facility, which matures on April 9, 2024. The Facility is secured by substantially all of the reserves associated with the Company's assets.

Any future borrowings bear interest, at the Company's option, at either the London Interbank Offered Rate ("LIBOR") plus 2.75% or the Prime Rate, as defined under the Facility, plus 1.0%. The Facility contains covenants requiring the maintenance of (i) a total leverage ratio of not more than 3.0 to 1.0, (ii) a current ratio of not less than 1.0 to 1.0, and (iii) a consolidated tangible net worth of not less than $40 million, each as defined in the Facility. The Facility also contains other customary affirmative and negative covenants and events of default. As of June 30, 2021, the Company was in compliance with all covenants contained in the Facility.

On August 5, 2021, and effective as of June 30, 2021, we entered into the seventh amendment of our Senior Secured Credit Facility which added definitions for the terms "Acquired Entity or Mineral Interests" and "Acquired Entity or Mineral Interests EBITDA Adjustment." Additionally, the Consolidated Tangible Net Worth was reduced to $40 million from $50 million.

The Company has historically funded operations through cash from operations and working capital. The primary source of cash is the sale of produced oil, natural gas, and natural gas liquids. A portion of these cash flows is used to fund capital expenditures. The Company expects to manage future development activities in the Delhi field and the limited capital maintenance requirements of the Hamilton Dome field and Barnett Shale assets within the boundaries of its operating cash flow and existing working capital.

The Company is pursuing new growth opportunities through acquisitions and other transactions. In addition to cash on hand, the Company has access to the undrawn portion of the borrowing base available under its senior secured credit facility. The Company also has an effective shelf registration statement with the SEC under which the Company may issue up to $500 million of new debt or equity securities.

During the fiscal year ended June 30, 2021, the Company funded operations, capital expenditures, and cash dividends with cash generated from operations resulting in a decrease of $14.4 million in cash. Uses of cash included the acquisition of the Barnett Shale assets ($18.3 million) and cash dividends on common shares ($4.3 million). As of June 30, 2021, working capital was $11.5 million, a decrease of $9.5 million from working capital of $21.0 million at June 30, 2020.

The Board of Directors instituted a cash dividend on common stock in December 2013. The Company has since paid 31 consecutive quarterly dividends. Distribution of a substantial portion of free cash flow in excess of operating and capital requirements through cash dividends remains a priority of the Company's financial strategy, and it is the Company's long-term goal to increase dividends over time, as appropriate. During the industry downturn, effective in the quarter ended June 30, 2020, the Board of Directors adjusted the quarterly dividend rate from $0.10 per share to $0.025 per share. The reduction in the dividend rate at that time allowed the Company to conserve cash for additional financial flexibility while continuing to reward shareholders with a yield of approximately 3% at stock price levels. On February 2, 2021, considering an improving industry outlook, the Board of Directors increased the dividend rate from $0.025 per share to $0.03 per share effective in the quarter ended March 31, 2021. On May 7, the Board of Directors further increased the dividend rate to $0.05 per share effective in the quarter ended June 30, 2021 due to improved industry conditions and the Barnett Shale acquisition. As in the past, the Company intends to consider higher dividend levels as warranted by industry conditions and any future accretive acquisitions.

Capital Expenditures

For the year ended June 30, 2021, we incurred $21.7 million on capital projects consisting of $21.1 million for the acquisition of Barnett Shale assets (gross of preliminary purchase price adjustments and $2.8 million in non-cash asset retirement obligations) and $0.6 million at the Delhi field (primarily for plugging costs and capital conformance work).

Based on discussions with the Delhi and Hamilton Dome operators, we expect to continue to perform conformance workover projects and will likely incur additional maintenance capital expenditures at Delhi and will resume projects at Hamilton Dome. Such amounts are not known or approved but we expect such expenditures to be in the range of $0.9 million to $1.5 million over the next 12 months. In addition, we have planned for Delhi Phase V development expenditures of approximately $1.9 million to be incurred in the fourth quarter of our fiscal 2023. Phase V development expenditures are expected to total $8.6 million with $3.7 million to be incurred in fiscal 2024 and the remainder over the following two years.

Our proved undeveloped reserves are associated only with the Delhi field. At June 30, 2021, our proved undeveloped reserves included 1.86 MMBOE of reserves and approximately $8.6 million of future development costs associated with Phase V development in the eastern portion of the Delhi field. Such development requires participation by both the operator and the Company. Although we expect drilling to commence in fiscal 2023, the timing of Phase V is dependent on the field operator's available funds, capital spending plans, and priorities within its portfolio of properties.

Funding for our anticipated capital expenditures over the next 24 months is expected to be met from cash flows from operations and current working capital.

Full Cost Pool Ceiling Test

At June 30, 2021, our capitalized costs of oil and natural gas properties were below the full cost valuation ceiling; however, we could experience an impairment if current price levels worsen. Lower oil prices would reduce the excess, or cushion, of our valuation ceiling over our capitalized costs and may adversely impact our ceiling tests in future quarters. We cannot give assurance that a write-down of capitalized oil and natural gas properties will not be required in the future. Under the full cost method of accounting, capitalized costs of oil and natural gas properties, net of accumulated DD&A and related deferred taxes, are limited to the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties, as adjusted for related income tax effects (the valuation "ceiling"). If capitalized costs exceed the full cost ceiling, the excess would be charged to expense as a write-down of oil and natural gas properties in the quarter in which the excess occurred. The quarterly ceiling test calculation requires that we use the average first day of the month price for our petroleum products during the 12-month period ending with the balance sheet date. The prices used in calculating our ceiling test at June 30, 2021 were $49.72 per barrel of oil, $2.46 per MMBtu of natural gas and $19.81 per barrel of natural gas liquids. At December 31, 2020 and September 30, 2020, the Company recorded ceiling test impairment charges of $15.2 million and $9.6 million, respectively. The ceiling test impairments were driven by decreases in the first-day-of-the-month average for oil used in the ceiling test calculation as outlined below. As of June 30, 2021, a 10% decrease in commodity prices used to determine our proved reserves would not have resulted in an impairment of our oil and natural gas properties.

	Twelve-Month Period Ended:				
	6/30/2020	9/30/2020	12/31/2020	3/31/2021	6/30/2021
Crude Oil	47.37	43.63	39.54	39.95	49.72
Natural Gas	2.12	2.02	2.03	2.18	2.46

Overview of Cash Flow Activities

The table below compares a summary of our consolidated statements of cash flows for year ended June 30, 2021 and 2020.

Increases (Decreases) in Cash:	June 30, 2021	June 30, 2020	Difference
		(In Millions)	
Net cash provided by operating activities	$ 4.7	$ 12.4	$ (7.7)
Net cash used in investing activities	(18.8)	(11.1)	(7.7)
Net cash used in financing activities	(0.3)	(13.2)	12.9
Change in cash, cash equivalents and restricted cash	$ (14.4)	$ (11.9)	$ (2.5)

Cash provided by operating activities in the current year decreased $7.7 million compared to fiscal 2020. The difference is primarily the result of a decrease in revenues compared to the prior year and the payments related to realized hedge settlement losses of $2.5 million.

Cash used in investing activities increased $7.7 million primarily due to the acquisition of the Barnett Shale assets in May 2021 for $18.3 million (net of preliminary purchase price adjustments and $2.8 million in non-cash asset retirement obligations) compared to the acquisition of Hamilton Dome field in November 2019 for $9.3 million. The increase is partially offset by a reduction in capital expenditures of $1.3 million in fiscal 2021 due to the decrease in conformance workover activities from lower oil prices.

Cash used in financing activities decreased year over year primarily related to the net borrowing of $4 million on the Senior Secured Credit Facility during fiscal 2021, and the reduction in cash paid for cash dividends as the Company paid $4.3 million in fiscal year 2021 and $10.7 million in fiscal year 2020. In addition, the Company paid $2.5 million more in fiscal year 2020 compared to fiscal year 2021 related to the Company's common share repurchase program.

Contractual Obligations and Other Commitments

The table below provides estimates of the timing of future payments that, as of June 30, 2021, we are obligated to make under our contractual obligations and commitments. We expect to fund these contractual obligations with cash on hand and cash generated from operations.

	Payments Due by Period				
	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Contractual Obligations					
AFE purchase commitments in connection with joint interest agreements	$ 329,827	$ 329,827	$ —	$ —	$ —
Operating lease	$ 84,978	59,103	25,875	—	—
Asset retirement obligations	$ 5,583,272	$ 44,520	$ 168,377	$ 158,378	$ 5,211,997
Total Obligations	$ 5,998,077	$ 433,450	$ 194,252	$ 158,378	$ 5,211,997

Results of Operations

Years Ended June 30, 2021 and 2020

Revenues

The following table summarizes total production volumes, daily production volumes, average realized prices and revenues for the years ended June 30, 2021 and 2020. Fiscal 2020 includes eight months of Hamilton Dome production. Fiscal 2021 includes approximately two months of Barnett Shale production.

	Years Ended June 30, 2021	Years Ended June 30, 2020	Variance	Variance %
Oil and gas production				
Revenues				
Oil	$ 26,411,132	$ 28,578,879	$ (2,167,747)	(7.6)%
Natural gas liquids	3,662,478	1,018,349	2,644,129	259.6 %
Natural gas	2,628,744	2,068	2,626,676	n.m.
Total revenues	$ 32,702,354	$ 29,599,296	$ 3,103,058	10.5 %
Volumes				
Oil (Bbl)	554,888	638,464	(83,576)	(13.1)%
Natural gas liquids (Bbl)	171,451	106,159	65,292	61.5 %
Natural gas (Mcf)	963,496	1,087	962,409	n.m.
Equivalent volumes (BOE)	886,922	744,804	142,118	19.1 %
Oil (BOPD, net)	1,520	1,744	(224)	(12.8)%
NGLs (BOEPD, net)	470	290	180	62.1 %
Natural gas (BOEPD, net)	440	—	440	n.m.
Equivalent volumes (BOEPD, net)	2,430	2,034	396	19.5 %
Oil average realized price per Bbl	$ 47.60	$ 44.76	$ 2.84	6.3 %
NGL average realized price per Bbl	21.36	9.59	11.77	122.7 %
Natural gas average realized price per Mcf	2.73	1.90	0.83	43.7 %
Equivalent price per BOE	$ 36.87 (a)	$ 39.74	$ (2.87)	(7.2)%

(a) Equivalent price per BOE has decreased in the current fiscal year despite a 6.3% increase in oil price per Bbl and a 122.7% increase in NGL price per Bbl. With the Barnett Shale Acquisition, the Company added significant natural gas sales compared to the prior year. Natural gas sales are realized at a lower price per BOE than oil and NGLs, and the Company's total weighted average price per BOE declined by approximately 7% from the prior year.

n. m. Not meaningful.

Fiscal year 2021 revenues increased 10% compared to the prior fiscal year primarily due to increased realized commodity prices and the addition of the Barnett Shale Acquisition, which primarily drove the increase in natural gas and NGL sales revenues and production volumes compared to the prior fiscal year. This increase was partially offset by an 8% decrease in oil revenues primarily driven by an expected temporary increase in production decline and weaker price differentials in the Delhi field. The shut-in of the CO_2 supply pipeline from late February 2020 through the end of October 2020, as discussed in "Lease Operating Costs" below, as well as a suspension of field conformance capital expenditures drove the expected temporary increase in production declines in the Delhi field. Purchased CO_2 is necessary to maintain reservoir pressure and therefore achieve normal field performance. The shut-in of purchased CO_2 volumes resulted in a decline in reservoir pressure and a temporary exacerbated production decline. The resumption of CO_2 purchases during the current fiscal year is expected to gradually restore reservoir pressure and lead to a gradual increase in oil production rates. Also contributing to the decrease of production in the current fiscal year was the loss of production associated with the severe winter storm in February 2021. The Company's average realized oil price was higher primarily due to the recovery of WTI pricing in 2021, as the demand for oil has begun to recover primarily as a result of the roll-out of the COVID -19 vaccines and concerns surrounding the perceived surplus of oil supplies has begun to retract.

(Gain) Loss on Derivative Contracts

Periodically, we utilize commodity derivative financial instruments to reduce our exposure to fluctuations in oil prices. This amount represents the (i) (gain) loss related to fair value adjustments on our open, or unrealized, derivative contracts and (ii) (gains) losses on settlements of derivative contracts for positions that have settled or been realized. No positions remain outstanding as of June 30, 2021.

	Years Ended June 30,			
	2021	2020	Variance	Variance %
Oil Derivative Contracts				
Realized (gain) loss on derivatives, net	$ 2,525,988	$ (528,139)	$ 3,054,127	(578.3)
Unrealized (gain) loss on derivatives	(1,911,343)	1,911,343	(3,822,686)	(200.0)
Loss on derivatives	$ 614,645	$ 1,383,204	$ (768,559)	(55.6)
Oil price per Bbl (including impact of realized derivatives)	$ 43.05	$ 45.59		

Lease Operating Costs

Lease operating costs (also referred to as production expenses) are presented in two components: (i) CO_2 purchase costs for the Delhi field and (ii) other lease operating costs for both the Delhi, Hamilton Dome, and Barnett Shale fields.

	Years Ended June 30,			
	2021	2020	Variance	Variance %
CO_2 costs (a)	$ 3,061,598	$ 3,501,507	$ (439,909)	(12.6)%
Other lease operating costs	13,525,454	10,003,995	3,521,459	35.2 %
Total lease operating costs	$ 16,587,052	$ 13,505,502	$ 3,081,550	22.8 %
CO_2 costs per BOE	$ 3.45	$ 4.70	$ (1.25)	(26.6)%
All other lease operating costs per BOE	15.25	13.43	1.82	13.6 %
Lease operating costs per BOE	$ 18.70	$ 18.13	$ 0.57	3.1 %

(a) Under our contract with the operator, purchased CO_2 is priced at 1% of the realized oil price in the field per Mcf, plus sales taxes and transportation costs as per contract terms.

	Years Ended June 30,			
	2021	2020	Variance	Variance %
CO_2 costs per mcf	$ 0.71	$ 0.77	$ (0.06)	(7.8)%
CO_2 volumes (MMcf per day, gross)	49.1	51.9	(2.8)	(5.4)%

The $0.4 million decrease in CO_2 costs was due to a 5.4% decrease in rate of purchased volumes together with a 7.8% decrease in price per Mcf associated with the lower realized oil price. The upstream pipeline that supplies CO_2 to the Delhi field was shut-in on February 22, 2020, when a pressure loss was detected. CO_2 purchases were suspended until October 2020 for pipeline repairs. CO_2 purchases provide approximately 20% of the injected volumes in the field and the field's recycle facilities provide the other 80%. The recycle facilities continued to operate as usual during the purchase pipeline suspension. The pipeline is owned and operated by Denbury Inc, and the Company does not have any ownership in the portion of the pipeline that was repaired.

Compared to fiscal 2020, "Other lease operating costs" increased 35.2% primarily due to the additional four months of production costs at the Hamilton Dome field in fiscal 2021 compared to eight months of production costs in fiscal 2020 following acquisition in November 2019 and, to a lesser extent, the closing of the Barnett Shale Acquisition in May 2021. The Delhi field's "Other lease operating costs" decreased 10.5% impacted by cost control measures resulting from lower oil prices.

Compared to fiscal 2020, Delhi field costs increased 14% to $18.80 per BOE of Delhi current year production primarily due to lower production volumes.

For fiscal 2021, Hamilton Dome field costs per BOE were $28.57, a decrease of 1.3% from fiscal year 2020 due to increased production and cost control measures implemented following the pandemic resulting from lower prices.

For fiscal 2021, Barnett Shale field costs per BOE were $12.61 compared to no field costs in the prior year as the Company completed the Barnett Shale Acquisition in the current fiscal year.

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

Total DD&A expense was 10.3% lower compared to the same one year-ago period due to an 12.3% decrease in the oil and natural gas DD&A amortization rate. The integration of the Barnett Shale assets together with the ceiling test impairments contributed to an overall lower composite DD&A per BOE rate. Additionally, accretion of asset retirement obligations increased 43.5% in the current fiscal year as a result of the asset retirement obligation additions from Barnett Shale Acquisition. Amortization of intangibles increased as a result of amortization of $37.3 thousand of our Well Lift, Inc. ("WLI") assets during fiscal year 2021.

	Years Ended June 30,			
	2021	2020	Variance	Variance %
DD&A of proved oil and gas properties	$ 4,901,969	$ 5,592,651	$ (690,682)	(12.3)%
Depreciation of other property and equipment	7,000	8,779	(1,779)	(20.3)%
Amortization of intangibles	47,474	13,564	33,910	250.0 %
Accretion of asset retirement obligations	210,183	146,504	63,679	43.5 %
Total DD&A	$ 5,166,626	$ 5,761,498	$ (594,872)	(10.3)%
Oil and gas DD&A per BOE	$ 5.53	$ 7.51	$ (1.98)	(26.4)%

General and Administrative Expenses

Total general and administrative expenses for fiscal 2021 increased $1.5 million, or 28.4%, to $6.8 million from the same year-ago period. The increase is primarily due to higher legal and professional fees of $0.8 million related to consulting on various potential business transactions, an increase in accrued bonus expense of $0.5 million and an increase in salaries of $0.2 million due to additional employees.

Other Income and Expenses

Interest income is lower in fiscal year 2021 compared to fiscal year 2020 primarily due to the decrease in cash as a result of the closing of the Barnett Shale Acquisition in May 2021 and lower realized oil prices.

	Years Ended June 30,			
	2021	2020	Variance	Variance %
Interest and other income	39,401	177,418	(138,017)	(77.8)%
Interest expense	(102,965)	(110,775)	7,810	(7.1)%
Total other income (expense), net	$ (63,564)	$ 66,643	$ (130,207)	(195.4)%

Net Income

Net income available to common stockholders for the year ended June 30, 2021 decreased $22.4 million, to a loss of $16.4 million compared to the last fiscal year primarily driven by proved oil and gas property impairments of $9.6 million and $15.2 million recorded during the first and second fiscal quarters of 2021, respectively. Our income tax benefit increased primarily due to a pre-tax loss in the current period compared to pre-tax income in the prior year. During the fiscal year 2020, we recorded a $2.8 million income tax benefit related to Enhanced Oil Recovery credits claimed on income tax returns for fiscal 2019, 2018 and 2017 compared to a $0.3 million EOR credit benefit in fiscal 2021.

	Years Ended June 30,			
	2021	2020	Variance	Variance %
Income (loss) before income tax provision	(21,422,195)	3,756,076	(25,178,271)	(670.3)%
Income tax provision (benefit)	(4,984,261)	(2,180,996)	(2,803,265)	128.5 %
Net income (loss) available to common shareholders	$ (16,437,934)	$ 5,937,072	$(22,375,006)	(376.9)%
Income tax provision (benefit) as a percentage of income before income	23 %	(58)%		

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America requires that we select certain accounting policies and make estimates and assumptions that affect the reported amounts of the assets, liabilities, and disclosures of contingent assets and liabilities as of the date of the balance sheet as well as the reported amounts of revenues and expenses during the reporting period. These policies, together with our estimates, have a significant effect on our consolidated financial statements. Our significant accounting policies are included in Note 2 to our consolidated statements in Item 8. Following is a discussion of our most critical accounting estimates, judgments, and uncertainties that are inherent in the preparation of our consolidated financial statements.

Oil and Natural Gas Properties. Companies engaged in the production of oil and natural gas are required to follow accounting rules that are unique to the oil and natural gas industry. We apply the full cost accounting method for our oil and natural gas properties as prescribed by SEC Regulation S-X Rule 4-10. Under this method of accounting, the costs of unsuccessful and successful, exploration and development activities are capitalized as properties and equipment. This includes any internal costs that are directly related to property acquisition, exploration, and development activities but does not include any costs related to production, general corporate overhead, or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves. Oil and natural gas properties include costs that are excluded from costs being depleted or amortized. Oil and natural gas property costs excluded represent investments in unevaluated properties. We exclude these costs until the property has been evaluated. Costs are transferred to the full cost pool as the properties are evaluated. As of June 30, 2021, we had no unevaluated property costs. Oil and natural gas properties include costs that are excluded from depletion and amortization, which represent investments in unproved and unevaluated properties and include non-producing leasehold, geologic and geophysical costs associated with leasehold or drilling interests, and exploration drilling costs.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense and the estimated future net cash flows associated with those proved reserves is the basis for determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex and requires significant decisions in the evaluation of all available geologic, geophysical, engineering, and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information; this includes reservoir performance, additional development activity, new geologic and geophysical data, additional drilling, technological advancements, price changes, and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates prepared by our third-party independent engineers represent the most accurate assessments possible, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and/or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves. These changes could affect our quarterly ceiling test calculation and could significantly affect our depletion rate. A 10% decrease in commodity prices used to determine our proved reserves as of June 30, 2021 would not have resulted in an impairment of our oil and natural gas properties. Holding all other factors constant, a reduction in the Company's proved reserve estimates at June 30, 2021 of 5%, 10% and 15% would affect depreciation, depletion, and amortization expense by approximately $64,500, $136,000, and $216,000, respectively.

On December 31, 2008, the SEC issued its final rule on the modernization of reporting oil and natural gas reserves. The rule allows consideration of new technologies in evaluating reserves, generally limits the designation of proved reserves to those projects forecast to be drilled five years from the initial recognition date of such reserves, allows companies to disclose their probable and possible reserves to investors, requires reporting of oil and natural gas reserves using an average price based on the previous 12-month unweighted arithmetic average first-day-of-the-month price rather than year-end prices, revises the disclosure requirements for oil and natural gas operations, and revises accounting for the limitation on capitalized costs for full cost companies.

Valuation of Deferred Tax Assets. We make certain estimates and judgments in determining our income tax expense for financial reporting purposes. These estimates and judgments occur in the calculation of certain tax assets and liabilities that arise from differences in the timing and recognition of revenue and expense for tax and financial reporting purposes. Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared or filed; therefore, we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits, and net operating loss carry backs and carry forwards. Adjustments related to these estimates are recorded in our tax provision in the period in which we file our income tax returns. Further, we must assess the likelihood that we will be able to recover or utilize our deferred tax assets. If recovery is not likely, we must record a valuation allowance against such deferred tax assets for the amount we would not expect to recover; this would result in an increase to our income

tax expense. As of June 30, 2021, we have recorded a valuation allowance for the portion of our net operating loss that is limited by Internal Revenue Code Section 382.

Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making the assessment of the ultimate realization of deferred tax assets. The Company establishes a valuation allowance against net operating losses and other deferred tax assets to the extent it believes the future benefit from these assets will not be realized in the statutory carryforward periods, based upon the level of historical taxable income and projections for future taxable income over the periods for which the deferred tax assets are deductible. At the time of this report, we have recorded a valuation allowance for our expected inability to realize the future benefits of certain federal and state deferred tax assets as further discussed in Note 13 - Income Taxes. If our estimates and judgments change regarding our ability to utilize our deferred tax assets, our tax provision would change in the period it is determined that recovery is probable.

Stock-based Compensation. The fair value and expected vesting period of the Company's market-based awards were determined using a Monte Carlo simulation. This technique uses a geometric Brownian motion model with defined variables and randomly generates values for each variable through multiple trials. Variables include stock price volatility, expected term of the award, the expected risk-free interest rate, and the expected dividend yield of the Company's stock. The risk-free interest rate used is the U.S. Treasury yield for bonds matching the expected term of the award on the date of grant. Vesting of market-based awards is based on the Company's total common stock return compared to a peer group of other companies in our industry with comparable market capitalizations and, for certain awards, the Company's share price attaining a set target.

Recent Accounting Pronouncements. Refer to Note 2 to our consolidated financial statements in Item 8 for discussion of the recent accounting pronouncements issued by the Financial Accounting Standards Board.

Off-Balance Sheet Arrangements

The Company had no off-balance sheet arrangements as of June 30, 2021.

Item 7A. Quantitative and Qualitative Disclosures About Market Risks

Interest Rate Risk

We are exposed to changes in interest rates. Changes in interest rates affect the interest earned on our cash and cash equivalents. Additionally, any borrowings under the Senior Secured Credit Facility will bear interest, at our option, at either LIBOR plus 2.75%, subject to a minimum LIBOR of 0.25%, or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%. LIBOR rates are sensitive to the period of contract and market volatility, as well as changes in forward interest rate yields. Under our current policies, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Derivative Instruments and Hedging Activity

We are exposed to various risks, including energy commodity price risk, such as price differentials between the NYMEX commodity price and the index price at the location where our production is sold. When oil, natural gas, and natural gas liquids prices decline significantly, our ability to finance our capital budget and operations may be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we monitor commodity prices to identify the potential need for the use of derivative financial instruments to provide partial protection against declines in oil prices. We do not enter into derivative contracts for speculative trading purposes. In early March 2020, oil prices declined rapidly. As a consequence of unprecedented commodity price volatility and uncertainty, on April 6, 2020 we elected to enter into NYMEX WTI oil swaps covering approximately 42,000 barrels per month for the period of April 2020 through December 2020, at a fixed swap price of $32 per barrel. The fixed price swap contracts significantly reduced volatility in our near-term realized oil price and resulting revenues, thus supporting our current business plans and objectives.

We are exposed to market risk on our open derivative contracts related to potential non-performance by our counterparties. It is our policy to enter into derivative contracts only with counterparties that are creditworthy institutions deemed by management as competitive market makers. For the derivative contracts settled during fiscal 2021, we did not post collateral as it was an uncollateralized trade. We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, (“ASC 815”). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 19 to our consolidated financial statements for more details.

Item 8. Consolidated Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Evolution Petroleum Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Evolution Petroleum Corporation and Subsidiaries (the "Company") as of June 30, 2021 and 2020, the related consolidated statements of operations, cash flows, and changes in stockholders' equity for 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 consolidated financial position of the Company as of June 30, 2021 and 2020, and the consolidated 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 to 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Natural Gas Reserves on Depreciation, Depletion and Amortization ("DD&A") and Full Cost Ceiling Test Impairment Calculation ("Ceiling Test")

As described in Note 2, the Company follows the full cost method of accounting, pursuant to which oil and natural gas properties are amortized using the unit-of-production method over total proved reserves. The Company's proved oil and natural gas properties are evaluated for impairment by the Ceiling Test, utilizing the Company's proved oil and natural gas reserves in accordance with accounting principles generally accepted in the United States of America and SEC guidelines. For the year ended June 30, 2021, the Company recorded DD&A related to its proved oil and natural gas properties of approximately $4.9 million and a ceiling test impairment of approximately $24.8 million.

The Company engages an independent reservoir engineering firm, to serve as a management specialist, to assist with the estimation of proved oil and natural gas reserves. To estimate the volume of proved oil and natural gas reserves and associated future net cash flows, management and their specialist make significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties ("PUDs"). The estimation of proved oil and natural gas reserves is impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required. Changes in significant assumptions or engineering data could have a significant impact on the amount of DD&A and impairment recorded for the Company's proved oil and natural gas properties.

We identified the impact of proved oil and natural gas reserves on DD&A and the Ceiling Test as a critical audit matter due to use of significant judgment by management, including the use of specialists, when developing the estimates of proved oil and natural gas reserves. This in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence related to the significant assumptions used in developing those estimates of proved oil and natural gas reserves.

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

- Evaluated significant assumptions used by management and its specialist in developing the estimates of proved oil and natural gas reserves, including pricing differentials, future operations costs, future production rates and capital expenditures. The procedures performed included:
    - tests of the data inputs used by specialist for completeness and accuracy,
    - an evaluation of the specialist's findings,
    - testing specialist's findings for mathematical accuracy and
    - analytical procedures on pricing, reserve quantities and cost estimates developed by management and its specialist. Those procedures entailed comparisons of:
        (i) prices to historical benchmark prices, adjusted for pricing differentials,
        (ii) production forecasts to recent historical actual production,
        (iii) projections of lease operating costs to fiscal year end costs, and
        (iv) projected production taxes to recent historical taxes incurred and to statutory tax rates.
- Evaluated the experience, qualifications and objectivity of management's specialist, an independent reservoir engineering firm.
- Evaluated the accuracy of revenue and working interest percentages used in the reserve report by comparing a sample of such interests to the land records.
- Evaluated the Company's evidence supporting the amount of PUDs reflected in the reserve report by (i) considering the field operator's intent to develop PUDs and (ii) testing the Company's financial capability to participate in development of those reserves by comparing estimated development costs to the sources of capital available to the Company.
- Performed retrospective review of historical estimates of proved oil and natural gas reserves to identify potential management bias in estimates.

/s/ Moss Adams LLP

Houston, Texas
September 14, 2021

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

Evolution Petroleum Corporation and Subsidiaries

Consolidated Balance Sheets

	June 30, 2021	June 30, 2020
Assets		
Current assets		
Cash and cash equivalents	$ 5,276,510	$ 19,662,528
Receivables from oil and gas sales	8,686,967	$ 1,919,213
Receivables for federal and state income tax refunds	3,107,638	3,243,271
Prepaid expenses and other current assets	1,037,259	491,686
Total current assets	18,108,374	25,316,698
Property and equipment, net of depreciation, depletion, and amortization		
Oil and natural gas properties—full-cost method of accounting, of which none were excluded from amortization	58,515,860	66,512,281
Other property and equipment, net	10,639	17,639
Total property and equipment, net	58,526,499	66,529,920
Other assets, net	70,789	291,618
Total assets	$ 76,705,662	$ 92,138,236
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 5,609,367	$ 1,471,679
Accrued liabilities and other	947,045	716,648
Derivative contract liabilities	—	1,911,343
State and federal taxes payable	37,748	179,189
Total current liabilities	6,594,160	4,278,859
Long term liabilities		
Senior secured credit facility	4,000,000	—
Deferred income taxes	5,957,202	11,061,023
Asset retirement obligations	5,538,752	2,588,894
Operating lease liability	20,745	84,978
Total liabilities	22,110,859	18,013,754
Commitments and contingencies		
Stockholders' equity		
Common stock; par value $0.001; 100,000,000 shares authorized: issued and outstanding 33,514,952 and 32,956,469 shares as of June 30, 2021 and 2020, respectively	33,515	32,956
Additional paid-in capital	42,541,224	41,291,446
Retained earnings	12,020,064	32,800,080
Total stockholders' equity	54,594,803	74,124,482
Total liabilities and stockholders' equity	$ 76,705,662	$ 92,138,236

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Operations

	Years Ended June 30, 2021	2020
Revenues		
Oil	$ 26,411,132	$ 28,578,879
Natural gas liquids	3,662,478	1,018,349
Natural gas	2,628,744	2,068
Total revenues	32,702,354	29,599,296
Operating costs		
Lease operating costs	16,587,052	13,505,502
Depreciation, depletion, and amortization	5,166,626	5,761,498
Impairment of proved property	24,792,079	—
Impairment of Well Lift Inc. - related assets	146,051	—
Net loss on derivative contracts	614,645	1,383,204
General and administrative expenses*	6,754,532	5,259,659
Total operating costs	54,060,985	25,909,863
Income (loss) from operations	(21,358,631)	3,689,433
Other		
Interest and other income	39,401	177,418
Interest expense	(102,965)	(110,775)
Income (loss) before income tax provision	(21,422,195)	3,756,076
Income tax expense (benefit)	(4,984,261)	(2,180,996)
Net income (loss) attributable to common shareholders	$ (16,437,934)	$ 5,937,072
Earnings (loss) per common share		
Basic	$ (0.49)	$ 0.18
Diluted	$ (0.49)	$ 0.18
Weighted average number of common shares outstanding		
Basic	33,263,701	33,031,149
Diluted	33,263,701	33,033,091

* General and administrative expenses for the years ended June 30, 2021 and 2020 included non-cash stock-based compensation expense of $1,257,684 and $1,285,663, respectively.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Cash Flows

	Years Ended June 30, 2021	2020
Cash flows from operating activities		
Net income (loss) attributable to common shareholders	$ (16,437,934)	$ 5,937,072
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	5,166,626	5,761,498
Impairment of proved property	24,792,079	—
Impairment of Well Lift Inc. - related assets	146,051	—
Stock-based compensation	1,257,684	1,285,663
Settlement of asset retirement obligations	(101,311)	(76,832)
Deferred income taxes	(5,103,821)	(261,668)
Net loss on derivative contracts	614,645	1,383,204
Payments received (paid) for derivative settlements	(2,791,176)	793,327
Other	10,316	39,783
Changes in operating assets and liabilities:		
Receivables	(6,632,121)	(1,994,368)
Prepaid expenses and other current assets	(545,573)	(33,408)
Accounts payable and accrued expenses	4,498,801	(486,010)
Income taxes payable	(141,441)	48,390
Net cash provided by operating activities	4,732,825	12,396,651
Cash flows from investing activities		
Acquisition of oil and gas properties	(18,297,013)	(9,337,716)
Development of oil and natural gas properties	(472,401)	(1,724,829)
Net cash used by investing activities	(18,769,414)	(11,062,545)
Cash flows from financing activities		
Common share repurchases, including shares surrendered for tax withholding	(7,347)	(2,483,357)
Common stock dividends paid	(4,342,082)	(10,740,754)
Borrowings under credit facility	7,000,000	—
Repayments of credit facility	(3,000,000)	—
Net cash provided by (used in) financing activities	(349,429)	(13,224,111)
Net decrease in cash, cash equivalents, and restricted cash	(14,386,018)	(11,890,005)
Cash, cash equivalents, and restricted cash, beginning of year	19,662,528	31,552,533
Cash, cash equivalents, and restricted cash, end of year *	$ 5,276,510	$ 19,662,528

* Neither annual period had any restricted cash balances.

See accompanying notes to consolidated financial statements.

Evolution Petroleum Corporation and Subsidiaries

Consolidated Statements of Changes in Stockholders' Equity

For the Years Ended June 30, 2021 and 2020

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock	Total Stockholders' Equity
	Shares	Par Value				
Balance, June 30, 2019	33,183,730	$ 33,183	$ 42,488,913	$ 37,603,762	$ —	$ 80,125,858
Issuance of restricted common stock	271,778	272	(272)	—	—	—
Forfeitures of restricted stock	(49,118)	(49)	49	—	—	—
Common share repurchases, including shares surrendered for tax withholding	—	—	—	—	(2,483,357)	(2,483,357)
Retirements of treasury stock	(449,921)	(450)	(2,482,907)	—	2,483,357	—
Stock-based compensation	—	—	1,285,663	—	—	1,285,663
Net income attributable to common shareholders	—	—	—	5,937,072	—	5,937,072
Common stock dividends paid	—	—	—	(10,740,754)	—	(10,740,754)
Balance, June 30, 2020	32,956,469	32,956	41,291,446	32,800,080	—	74,124,482
Issuance of restricted common stock	561,115	562	(562)	—	—	—
Common share repurchases, including shares surrendered for tax withholding	—	—	—	—	(7,347)	(7,347)
Retirements of treasury stock	(2,632)	(3)	(7,344)	—	7,347	—
Stock-based compensation	—	—	1,257,684	—	—	1,257,684
Net loss attributable to the Company	—	—	—	(16,437,934)	—	(16,437,934)
Common stock dividends paid	—	—	—	(4,342,082)	—	(4,342,082)
Balance, June 30, 2021	33,514,952	$ 33,515	$ 42,541,224	$ 12,020,064	$ —	$ 54,594,803

See accompanying notes to consolidated financial statements.

Note 1 – Organization and Basis of Preparation

Nature of Operations. Evolution Petroleum Corporation is an oil and natural gas company focused on delivering a sustainable dividend yield to its stockholders through the ownership, management, and development of producing oil and natural gas properties. The Company's long-term goal is to build a diversified portfolio of oil and natural gas assets primarily through acquisitions while seeking opportunities to maintain and increase production through selective development, production enhancement, and other exploitation efforts on its properties.

Our producing assets consist of our interests in the Delhi Holt-Bryant Unit in the Delhi field in Northeast Louisiana, a CO_2 enhanced oil recovery ("EOR") project, our interests in the Hamilton Dome field located in Hot Springs County, Wyoming, a secondary recovery field utilizing water injection wells to pressurize the reservoir, our interests in the Barnett Shale located in North Texas, a natural gas producing shale reservoir, and overriding royalty interests in two onshore Texas wells.

Principles of Consolidation and Reporting. Our consolidated financial statements include the accounts of Evolution Petroleum Corporation and its wholly-owned subsidiaries (the "Company"). All significant intercompany transactions have been eliminated in consolidation. The consolidated financial statements for the previous year may include certain reclassifications to conform to the current presentation. Any such reclassifications have no impact on previously reported net income or stockholders' equity.

Risk and Uncertainties. The Company is continuously monitoring impacts of the COVID-19 pandemic on its business, including how it has and may continue to impact its financial results, liquidity, employees, and the operations of the Delhi field, Hamilton Dome fields, and its Barnett Shale assets in which it holds non-operated interests.

In response to the pandemic, the operator at Hamilton Dome temporarily shut-in some producing wells. In addition to the above, the pandemic slowed the repair schedule of the Delhi CO_2 supply pipeline which, together with the foregoing, negatively impacted our production. All of the Company's property interests are not operated by the Company and involve other third-party working interest owners. As a result, the Company has limited ability to influence or control the operation or future development of such properties. However, the Company has been proactive with its third-party operators to review spend and alter plans as appropriate.

The Company is focused on putting long term measures to prevent future disruptions, maintaining its operations and system of controls remotely and has implemented its business continuity plans in order to allow its employees to securely work from home or in the corporate office. The Company was able to transition the operation of its business with minimal disruption and has maintained its system of internal controls and procedures.

Use of Estimates. The preparation of financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the dates of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant estimates include (a) reserve quantities and estimated future cash flows associated with proved reserves, which may significantly impact depletion expense and potential impairments of oil and natural gas properties, (b) asset retirement obligations, (c) stock-based compensation, (d) fair values of derivative assets and liabilities, (e) income taxes and the valuation of deferred tax assets, (f) commitments and contingencies and (g) oil, natural gas, and NGL revenues. We analyze our estimates based on historical experience and various other assumptions that we believe to be reasonable. While we believe that our estimates and assumptions used in preparation of the consolidated financial statements are appropriate, actual results could differ from those estimates.

Note 2 – Summary of Significant Accounting Policies

Cash and Cash Equivalents. We consider all highly liquid investments, with original maturities of 90 days or less when purchased, to be cash and cash equivalents.

Restricted Cash. Funds legally designated for a specified purpose are classified as restricted cash. Such a balance is classified on the statement of financial position as either current or non-current depending on its expected use. At June 30, 2021 and 2020, we had no such balances.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable consist of accrued hydrocarbon revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production, and other miscellaneous receivables. No interest is charged on past-due balances. Payments made on accounts receivable are applied to the earliest unpaid items. We establish provisions for losses on accounts receivable if it is determined that collection of all or a part of an outstanding balance is not probable. Collectability is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method. As of June 30, 2021 and 2020, no allowance for doubtful accounts was considered necessary.

Oil and Natural Gas Properties. We use the full-cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs incurred in the acquisition, exploration and development of oil and natural gas properties, including unproductive wells, are capitalized. This includes any internal costs that are directly related to property acquisition, exploration, and development activities but does not include any costs related to production, general corporate overhead, or similar activities. Gain or loss on the sale or other disposition of oil and natural gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves.

Oil and natural gas properties include costs that are excluded from depletion and amortization, which represent investments in unproved and unevaluated properties and include non-producing leasehold, geologic and geophysical costs associated with leasehold or drilling interests, and exploration drilling costs. These costs are excluded until the project is evaluated and proved reserves are established or impairment is determined. As of June 30, 2021 and 2020, we did not have any costs excluded from depletion and amortization.

Limitation on Capitalized Costs. Under the full-cost method of accounting, we are required, at the end of each fiscal quarter, to perform a test to determine the limit on the book value of our oil and natural gas properties (the “Ceiling Test”). If the capitalized costs of our oil and natural gas properties, net of accumulated amortization and related deferred income taxes, exceed the “Ceiling”, this excess or impairment is charged to expense and reflected as additional accumulated depreciation, depletion, and amortization or as a credit to oil and natural gas properties. The expense may not be reversed in future periods, even though higher oil and natural gas prices may subsequently increase the Ceiling. The Ceiling is defined as the sum of: (a) the present value, discounted at 10 percent and assuming continuation of existing economic conditions, of 1) estimated future gross revenues from proved reserves, which is computed using oil and natural gas prices determined 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 (with consideration of price changes only to the extent provided by contractual arrangements including hedging arrangements pursuant to SAB 103), less 2) estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves; plus (b) the cost of properties not being amortized (pursuant to Reg. S-X Rule 4-10 (c)(3)(ii)); plus (c) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; net of (d) the related tax effects related to the difference between the book and tax basis of our oil and natural gas properties. See Note 6 - Property and Equipment for further information about impairment for the year ended June 30, 2021.

Other Property and Equipment. Other property and equipment includes building leasehold improvements, data processing and telecommunications equipment, office furniture, and office equipment. These items are recorded at cost and depreciated over expected lives of the individual assets or group of assets, which range from three to seven years. The assets are depreciated using the straight-line method. Realization of the carrying value of other property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Assets are determined to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset, including disposal value, if any, is less than the carrying amount of the asset. If any asset is determined to be impaired, the loss is measured as the amount by which the carrying amount of the asset exceeds its fair value. Repairs and maintenance costs are expensed in the period incurred.

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred Financing Costs. The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in other assets on the Company's consolidated balance sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method.

Asset Retirement Obligations. An asset retirement obligation associated with the retirement of a tangible long-lived asset is recognized as a liability in the period incurred. It is associated with an increase in the carrying amount of the related long-lived asset, our oil and natural gas properties. The cost of the tangible asset, including the asset retirement cost, is depleted over the useful life of the asset. The initial recognition or subsequent revision of asset retirement cost is considered a Level 3 fair value measurement. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at our credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, derivative instruments, and debt. Except for derivatives, the carrying amounts of cash and cash equivalents, accounts receivable and accounts payable are short-term instruments and approximate fair value due to their highly liquid nature. The carrying amount of debt approximates fair value as the variable rates on the Senior Secured Credit Facility are market interest rates. The fair values of the Company’s derivative assets and liabilities are based on a third-party industry-standard pricing model that uses market data obtained from third-party sources, including quoted forward prices for oil and natural gas, discount rates, and volatility factors.

Stock-based Compensation. We estimate the fair value of stock-based compensation awards on the grant date to provide the basis for future compensation expense. Service-based and performance-based Restricted Stock and Contingent Restricted Stock awards (as defined in Note 11 - Stock-Based Incentive Plan) are valued using the market price of our common stock on the grant date. Market-based awards are valued using a Monte Carlo simulation and geometric Brownian motion techniques applied to the historical volatility of the Company's total stock return compared to the historical volatilities of other companies or indices to which we compare our performance. This Monte Carlo simulation also provides an expected vesting period. For service-based awards, stock-based compensation is recognized ratably over the service period. For performance-based awards, stock-based compensation is recognized ratably over the expected vesting period when it is deemed probable, for accounting purposes, that the performance goal will be achieved. The expected vesting period may be shorter than the remaining term. For market-based awards, stock-based compensation expense is recognized ratably over the expected vesting period, so long as the award holder remains an employee of the Company. Total compensation expense is independent of vesting or expiration of the awards, except for termination of service.

Revenue Recognition - Oil and Natural Gas. Our revenues are comprised solely of revenues from customers from the sale of oil, natural gas, and natural gas liquids. The Company believes that the disaggregation of revenue on its consolidated statements of operations into these three major product types appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors based on our geographic locations. Oil, natural gas, and natural gas liquids revenues are recognized at a point in time when production is sold to a purchaser at an index-based, determinable price, delivery has occurred, control has transferred and collectability of the revenue is probable. The transaction price used to recognize revenue is a function of the contract billing terms which reference index price sources used by the industry. Revenue is invoiced by calendar month based on volumes at contractually based rates with payment typically required within 30 days for oil and 60 days for natural gas and natural gas liquids after the end of the production month. At the end of each month when the performance obligations have been satisfied, the consideration can be reasonably estimated and amounts due from customers (remitted to us by field operators) are accrued in “Receivables from oil and gas sales” in our consolidated balance sheets. As of June 30, 2021 and 2020 receivables from contracts with customers were $8.7 million and $1.9 million, respectively. This increase was related primarily to approximately two months of accrued revenue from the Barnett Shale Acquisition. For additional revenue recognition information see Note 3 - Revenue Recognition.

Estimates of Proved Reserves. The estimated quantities of proved oil and natural gas reserves have a significant impact on the underlying financial statements. The estimated quantities of proved reserves are used to calculate depletion expense and the estimated future net cash flows associated with those proved reserves is the basis for determining impairment under the quarterly ceiling test calculation. The process of estimating oil and natural gas reserves is very complex and requires significant decisions in the evaluation of all available geologic, geophysical, engineering, and economic data. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information; this includes reservoir performance, additional development activity, new geologic and geophysical data, additional drilling, technological advancements, price changes, and other economic factors. As a result, material revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that the reported reserve estimates prepared by our third-party independent engineers represent the most accurate assessments possible, the subjective decisions and variances in available data for the properties make these estimates generally less precise than other estimates included in our financial statements. Material revisions to reserve estimates and/or significant changes in commodity prices could substantially affect our estimated future net cash flows of our proved reserves. These changes could affect our quarterly ceiling test calculation and could significantly affect our depletion rate.

Derivative Instruments. The Company follows ASC 815, Derivatives and Hedging ("ASC 815"). From time to time, in accordance with the Company's policy, it may hedge a portion of its forecasted oil, natural gas, and natural gas liquids production. All derivative instruments are recorded on the consolidated balance sheet as either an asset or liability measured at fair value. The Company nets its derivative instrument fair value amounts executed with the same counterparty pursuant to an International Swap Dealers Association Master Agreement ("ISDA") master agreement; the agreement provides for net settlement over the term of the contract and in the event of default or termination of the contract. Although the derivative instruments provide an economic hedge of the Company's exposure to commodity price volatility, the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in "Net (gain) loss on derivative instruments" on the consolidated statements of operations.

Depreciation, Depletion, and Amortization ("DD&A"). The depreciable base for oil and natural gas properties includes the sum of all capitalized costs net of DD&A, estimated future development costs, and asset retirement costs (net of salvage values) not included in oil and natural gas properties, less costs excluded from amortization. The depreciable base of oil and natural gas properties is amortized using the unit-of-production method over total proved reserves. Other property, consisting of leasehold building improvements and office and computer equipment, is depreciated as described above in Other Property and Equipment.

Income Taxes. We recognize deferred tax assets and liabilities based on the differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that may result in taxable or deductible amounts in future years. The measurement of deferred tax assets may be reduced by a valuation allowance based upon management's assessment of available evidence if it is deemed more likely than not that some or all of the deferred tax assets will not be realizable. We recognize a tax benefit from an uncertain position when it is more likely than not that the position will be sustained upon examination which is based on the technical merits of the position. We record the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement with a taxing authority. The Company classifies any interest and penalties associated with income taxes as income tax expense.

Earnings (Loss) Per Share. Basic earnings (loss) per share ("EPS") is computed by dividing earnings or loss available to common stockholders by the weighted-average number of common shares outstanding during the period. The computation of diluted EPS is similar to the computation of basic EPS, except that the denominator is increased to include the number of additional common shares that would have been outstanding if potentially dilutive common shares had been issued. Potentially dilutive common shares are our contingent restricted common stock. We use the treasury stock method to determine the effect of potentially dilutive common shares on diluted EPS, unless the effect would be anti-dilutive. Under this method, exercise of contingent restricted common stock, under certain condition, is assumed to have occurred at the beginning of the period (or at time of issuance, if later); common shares are assumed to have been issued. The unamortized stock compensation expense related to restricted common stock are assumed to be used to repurchase common stock at the average market price during the period. The incremental shares (the difference between the number of shares assumed issued and the number of shares assumed repurchased) are included in the denominator of the diluted EPS computation. Contingent restricted stock is included in the computation of diluted shares, if dilutive, when the underlying performance conditions either (i) were satisfied as of the end of the reporting period or (ii) would be considered satisfied if the end of the reporting period were the end of the related contingency period.

Recently Adopted Accounting Pronouncements

Leases. Effective July 1, 2019, the Company adopted the new standard using a modified retrospective approach and elected to use the optional transition methodology whereby reporting periods prior to adoption continue to be presented in accordance with legacy accounting guidance, Accounting Standard Codification 840 - Leases. Upon transition, we recognized a right of use ("ROU") asset (or operating lease right-of-use asset) and an operating lease liability with no retained earnings impact. We applied the following practical expedients as provided in the standards update which provide elections to not reassess:

- Not to apply the recognition requirements in the lease standard to short-term leases (a lease that at commencement date has a lease term of 12 months or less and does not contain a purchase option that the Company is reasonably certain to exercise).
- Whether an expired or existing pre-adoption date contracts contained leases.
- Lease classification of any expired or existing leases.
- Initial direct costs for any expired or existing leases.
- Not to separate lease components from non-lease components in a contract and accounting for the combination as a lease (reflected by asset class).

Adoption of the new standard did not impact our consolidated statements of operations, cash flows or stockholders' equity.

Income Taxes. In December 2019, the FASB issued Accounting Standards Update (ASU) 2019-12, Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes (ASU 2019-12) as part of its initiative to reduce complexity in the accounting standards. The amendments in ASU 2019-12 remove certain exceptions related to the incremental approach for intraperiod tax allocation and the general methodology for calculating income taxes in an interim period and reducing diversity in practice for the recognition of enacted changes in tax law. ASU 2019-12 also clarifies and simplifies other aspects of accounting for income taxes. ASU 2019-12 is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2020; however, early adoption is permissible for periods for which financial statements have not yet been issued. Effective October 1, 2020, the Company prospectively adopted this new standard. Adoption of this standard had no impact on our consolidated financial statements nor would it have had if we had adopted the standard on July 1, 2020.

Recently Issued Accounting Pronouncements

In June 2016, the FASB issued ASU 2016-13, Financial Instruments - Credit Losses ("ASU 2016-13"). ASU 2016-13 changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, and requires the use of a new forward-looking expected loss model that will result in the earlier recognition of allowances for losses. Early adoption is permitted and entities must adopt the amendment using a modified retrospective approach to the first reporting period in which the guidance is effective. For smaller reporting companies, as provided by Accounting Standards Update 2019-10, Financial Instruments - Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842), ASU 2016-13 is effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2022. The adoption of ASU 2016-13 is currently not expected to have a material effect on our consolidated financial statements.

Other accounting pronouncements that have recently been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company's financial position, results of operations, or cash flows.

Note 3 – Revenue Recognition

Our revenue is primarily generated from our interests in the Delhi field in Northeast Louisiana, the Barnett Shale assets of North Texas, and the Hamilton Dome field in Wyoming. Additionally, an overriding royalty interest retained in a past divestiture of Texas properties provided de minimis revenue:

	June 30, 2021	June 30, 2020
Revenues		
Oil	$ 26,411,132	$ 28,578,879
Natural gas liquids	3,662,478	1,018,349
Natural gas	2,628,744	2,068
Total revenues	$ 32,702,354	$ 29,599,296

We are a non-operator and presently do not take production in-kind and do not negotiate contracts with customers. We recognize oil, natural gas, and natural gas liquids production revenue at the point in time when custody and title ("control") of the product transfers to the customer. Transfer of control drives the presentation of post-production expenses such as transportation, gathering, and processing deductions within the accompanying statements of operations. Fees and other deductions incurred prior to control transfer are recorded within the lease operating costs line item on the accompanying consolidated statements of operations, while fees and other deductions incurred subsequent to control transfer are embedded in the price and effectively recorded as a reduction of oil, natural gas, and natural gas liquids production revenue. Transfer of control related to the Barnett Shale production does not occur until after the marketing, transportation and processing services have been performed, and as such, fees related to these services are recorded within the lease operating costs line item and do not reduce the oil, natural gas, and natural gas liquids production revenue. Transfer of control related to the Hamilton Dome and Delhi production occurs prior to the fees and other deductions, and as such, these fees are recorded as a reduction to the oil and natural gas liquids production revenue.

Judgments made in applying the guidance in Accounting Standards Codification Topic 606, Revenue from Contracts with Customers, relate primarily to determining the point in time when control of product transfers to the customer. The Company does not believe that significant judgments are required with respect to the determination of the transaction price, including amounts that represent variable consideration, as volume and price carry a low level of estimation uncertainty given the precision of volumetric measurements and the use of index pricing with predictable differentials. Accordingly, the Company does not consider estimates of variable consideration to be constrained.

The Company's contractual performance obligations arise upon the production of hydrocarbons from wells in which the Company has an ownership interest. The performance obligations are considered satisfied at a point in time upon control transferring to a customer at a specified delivery point. Consideration is allocated to completed performance obligations at the end of an accounting period.

Revenue is recorded in the month when contractual performance obligations are satisfied. However, settlement statements from the purchasers of hydrocarbons and the related cash consideration are received by field operators before distributing the Company's share one to two months after production has occurred, which is typical in the industry. As a result, the Company must estimate the amount of production delivered to the customer and the consideration that will ultimately be received for the sale of the product. Estimated revenue due to the Company is recorded within the "Receivables from oil and gas sales" line item on the accompanying consolidated balance sheets until payment is received from field operators. The accounts receivable balances from contracts with customers as of June 30, 2021 and 2020, as presented on our respective consolidated balance sheets, were $8.7 million and $1.9 million, respectively. The increase between fiscal 2020 and fiscal 2021 is primarily due to the Barnett Shale Acquisition. To estimate accounts receivable from operators' contracts with customers, the Company uses knowledge of its properties, historical performance, contractual arrangements, index pricing, quality and transportation differentials, and other factors as the basis for these estimates. Differences between estimates and actual amounts received for product sales are recorded in the month that payment is received from the purchaser as remitted to us by field operators. Revenue recognized during the fiscal year ended June 30, 2021 and 2020 related to performance obligations satisfied in prior reporting periods, was immaterial.

Note 4 – Leases

Operating leases are reflected as an operating lease ROU asset included in "Other assets, net", and as a ROU liability in "Accrued liabilities and other" and "Operating lease liability" on our consolidated balance sheets. Operating lease ROU assets and liabilities are recognized at the commencement date of an arrangement based on the present value of lease payments over the lease term. In addition to the present value of lease payments, the operating lease ROU asset would also include any lease payments made to the lessor prior to lease commencement less any lease incentives and initial direct costs incurred, if any. Lease expense for operating lease payments is recognized on a straight-line basis over the lease term. Certain leases have payment terms that vary based on the usage of the underlying assets. Variable lease payments are not included in ROU assets

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

and lease liabilities. For all operating leases, lease and non-lease components are accounted for as a single lease component.

As a non-operator in recent years and having adequate liquidity, the Company has generally not entered into lease transactions. Presently, our only operating lease is for corporate office space in Houston, Texas, effective May 1, 2019 and which expires November 30, 2022. Presently we have one operating lease for office space, no finance leases, and no short-term leases.

The Company makes certain assumptions and judgments when evaluating a contract that meets the definition of a lease under Topic 842. At adoption, July 1, 2019, as our lease did not provide an implicit rate, we used our prime-rate-based borrowing rate under our senior secured credit facility as our incremental borrowing as the term facility was based on a similar term and is appropriately risk-adjusted. We determined lease term by considering any option available to extend or to early terminate the lease which we believed was reasonably certain to be exercised.

At June 30, 2021, maturities of our operating lease liability are as follows:

Fiscal Year	Operating Lease Liability
2022	61,843
2023	26,098
Total lease payments	87,941
Less imputed interest	(2,962)
Total lease liability	$ 84,979

Supplemental cash flow, balance sheet, and other disclosures information related to our operating leases are as follows:

	As of and For the Year Ended June 30, 2021	As of and For the Year Ended June 30, 2020
Cash Flow:		
Cash paid for amounts included in the measurement of lease liabilities	$ 59,945	$ 4,903
ROU asset added in exchange for lease obligation at adoption	—	161,125
Balance Sheet:		
Operating lease ROU asset (included in other assets)	70,789	117,193
Accrued liabilities - current	64,234	54,290
Operating lease liability - long-term	20,745	84,978
Other:		
Weighted average remaining lease term in years	1.34	2.66
Weighted average discount rate	5.15 %	5.15 %

Note 5 – Prepaid Expenses and Other Current Assets

	June 30, 2021	June 30, 2020
Prepaid insurance	$ 365,922	$ 289,999
Prepaid subscription and licenses	108,048	67,005
Prepaid federal and state income taxes	97,470	86,208
Carryback of EOR tax credit	416,441	—
Prepaid other	49,378	48,474
Total prepaid expenses and other current assets	$ 1,037,259	$ 491,686

Note 6 – Property and Equipment, Net of Depreciation, Depletion, and Amortization

	June 30, 2021	June 30, 2020
Oil and natural gas properties:		
Property costs subject to amortization	$ 129,123,227	$ 107,390,379
Less: Accumulated depreciation, depletion, and amortization and impairment (a)	(70,607,367)	(40,878,098)
Unproved properties not subject to amortization	—	—
Oil and natural gas properties, net	58,515,860	66,512,281
Other property and equipment:		
Furniture, fixtures, and office equipment, at cost	154,731	154,731
Less: Accumulated depreciation (b)	(144,092)	(137,092)
Other property and equipment, net	$ 10,639	$ 17,639

(a) Depletion on oil and natural gas properties was $4,901,969 for fiscal 2021 and $5,592,651 for fiscal 2020. Impairment on oil and natural gas properties was $24,792,079 for fiscal 2021, and there was no impairment in fiscal 2020.

(b) Depreciation was $7,000 for fiscal 2021 and $8,779 for fiscal 2020.

As of June 30, 2021 and 2020, all oil and gas property costs were being amortized.

During the years ended June 30, 2021 and 2020, the Company incurred capital expenditures of $0.6 million and $1.5 million, respectively.

On May 7, 2021, the Company acquired an approximate 17% working interest and a 14% revenue interest in non-operated oil and gas assets in the Barnett Shale from Tokyo Gas Americas for $18.3 million, net of preliminary purchase price adjustments, and also recognized $2.8 million in non-cash asset retirement obligations. The Company accounted for this transaction as an asset acquisition with an effective of January 1, 2021.

On November 1, 2019, the Company acquired a 23.5% non-operated working interest and a 19.7% revenue interest in the Hamilton Dome unitized field located in Hot Springs County, Wyoming, from the Merit Energy Company. As a result of this cash purchase combined with its subsequent purchase adjustments, the Company recorded a purchase cost of $9.3 million, net of purchase price adjustments, and also recognized $0.9 million in non-cash asset retirement obligations. The Company accounted for this transaction as an asset acquisition.

In accordance with the Financial Accounting Standards Board's authoritative guidance on asset acquisitions, the Company allocated the cost of the acquisition to the assets acquired and liabilities assumed based on a relative fair value basis of the assets acquired and liabilities assumed, with no recognition of goodwill or bargain purchase gain recorded. Incremental legal and professional fees related directly to the Acquisition were capitalized as part of the Acquisition cost. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize market assumptions of market participants.

The Company uses the full cost method of accounting for its investments in oil and natural gas properties. All costs of acquisition, exploration, and development of oil and natural gas reserves are capitalized as the cost of oil and natural gas and properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion, exceed the discounted future net revenues of proved oil and natural gas reserves, net of deferred taxes, such excess capitalized costs result in an impairment charge.

At June 30, 2021, the ceiling test value of the Company's reserves was calculated based on the first-day-of-the-month average for the 12-months ended June 30, 2021 of the West Texas Intermediate (WTI) oil spot price of $49.72 per barrel and Henry Hub natural gas spot price of $2.46 per MMBtu, adjusted by market differentials by field. The net price per barrel of NGLs was $19.81, which does not have any single comparable reference index price. The NGL price was based on historical prices received. Using these prices, the Company's net book value of oil and natural gas properties at June 30, 2021 did not exceed the current ceiling.

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At December 31, 2020 and September 30, 2020, the Company recorded ceiling test impairment charges of $15.2 million and $9.6 million, respectively. The ceiling test impairments were driven by decreases in the first-day-of-the-month average for oil used in the ceiling test calculation, from $47.37 per barrel at June 30, 2020 to $43.63 per barrel at September 30, 2020 to $39.54 per barrel at December 31, 2020.

Note 7 – Other Assets, Net

	June 30, 2021	June 30, 2020
Royalty rights	—	108,512
Less: Accumulated amortization of royalty rights	—	(61,037)
Investment in Well Lift Inc., at cost	—	108,750
Deferred loan costs	168,972	168,972
Less: Accumulated amortization of deferred loan costs	(168,972)	(157,084)
Right of use asset under operating lease	161,125	161,125
Less: Accumulated amortization of right of use asset	(90,336)	(43,932)
Software license	20,662	20,662
Less: Accumulated amortization of software license	(20,662)	(14,350)
Other assets, net	$ 70,789	$ 291,618

Our royalty rights and investment in WLI resulted from the separation of our artificial lift technology operations in December 2015. We conveyed our patents and other intellectual property to WLI and retained a 5% royalty on future gross revenues associated with the technology. We own 17.5% of the common stock and 100% of the preferred stock of WLI and account for our investment in this private company at cost less impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or a similar investment of the same issuer, if such were to occur. The Company evaluates the investment for impairment when it identifies any events or changes in circumstances that might have a significant adverse effect on the fair value of the investment. At March 31, 2021, we reviewed our investment and technology rights in WLI for potential impairment and, as a result, recorded an impairment expense of $0.1 million. This impairment charge was recorded based on a variety of factors including the lack of current revenue generated and the outlook for future activity associated with this technology primarily due to a reduction in drilling activities across the industry.

Note 8 – Accrued Liabilities and Other

	June 30, 2021	June 30, 2020
Accrued incentive and other compensation	$ 630,744	$ 176,636
Accrued retirement costs	52,786	—
Accrued franchise taxes	35,207	100,978
Accrued ad valorem taxes	108,000	108,000
Payable for settled derivatives	—	265,188
Operating lease liability, current	64,234	54,290
Asset retirement obligations due within one year	44,520	—
Accrued - other	11,554	11,556
Total Accrued liabilities and other	$ 947,045	$ 716,648

Note 9 – Asset Retirement Obligations

Our asset retirement obligations represent the estimated present value of the amount we expect to incur to plug, abandon, and remediate our producing properties at the end of their productive lives in accordance with applicable laws and regulations. During the year ended June 30, 2021, the Delhi field operator abandoned two wells. Presently, we expect the Hamilton Dome operator to plug four wells during the next twelve months. The following is a reconciliation of the beginning and ending asset retirement obligations for the years ended June 30, 2021 and 2020:

	Years Ended 2021		2020
Asset retirement obligations — beginning of period	$ 2,588,894		$ 1,610,845
Liabilities incurred	—		40,698
Liabilities settled	(99,231)	(a)	(86,592)
Liabilities acquired	2,806,331	(b)	903,580
Accretion of discount	210,182		146,504
Revisions of previous estimates	77,096	(c)	(26,141)
Asset retirement obligations — end of period	5,583,272		2,588,894
Less: current asset retirement obligations	44,520		—
Long-term portion of asset retirement obligations	$ 5,538,752		$ 2,588,894

(a) Abandonment of two non-scheduled Delhi field wells in fiscal 2021, and abandonment of one Delhi field well and four Hamilton Dome field wells in fiscal 2020.

(b) Liabilities acquired in fiscal 2021 and 2020 were primarily due to our acquisition of the Barnett Shale interest and the Hamilton Dome interest, respectively.

(c) Primarily related to upward revisions for two difficult-to-plug Delhi field wells in fiscal 2021.

Note 10 – Stockholders' Equity

Common Stock

As of June 30, 2021, we had 33,514,952 shares of common stock outstanding.

The Company began paying quarterly cash dividends on common stock in December 2013. As of June 30, 2021, we have cumulatively paid over $74.5 million in cash dividends. We paid dividends of $4,342,082 and $10,740,754 to our common stockholders during the years ended June 30, 2021 and 2020, respectively. The following table reflects the dividends paid within the respective three-month periods:

	Fiscal Year 2021	2020
Fourth quarter ended June 30,	$0.050	$0.025
Third quarter ended March 31,	$0.030	$0.100
Second quarter ended December 31,	$0.025	$0.100
First quarter ended September 30,	$0.025	$0.100

In May 2015, the Board of Directors approved a share repurchase program covering up to $5.0 million of the Company's common stock. Since inception of the program through June 30, 2021, the Company has spent $4.0 million to repurchase 706,858 common shares at an average price of $5.72 per share. There were no shares purchased under this program during the year ended June 30, 2021. Under the program's terms, shares are repurchased only on the open market and in accordance with the requirements of the SEC. Such shares are initially recorded as treasury stock, then subsequently canceled. The timing and amount of repurchases depends upon several factors, including financial resources and market and business conditions. There is no fixed termination date for this repurchase program, and it may be suspended or discontinued at any time.

During the year ended June 30, 2021 and 2020, the Company also acquired treasury stock from holders of newly vested stock-based awards to fund the recipients' payroll tax withholding obligations. The treasury shares were subsequently canceled. Such shares were valued at fair market value on the date of vesting. The following table shows all treasury stock purchases in the last two fiscal years:

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	Common Shares Acquired	Average Price per Share	Treasury Stock Purchases
Year Ended June 30, 2021:			
Shares surrendered for tax withholding upon vesting	2,632	$ 2.79	$ 7,347
Share repurchase program	—	$ —	—
Total	2,632	$ 2.79	$ 7,347
Year Ended June 30, 2020:			
Shares surrendered for tax withholding upon vesting	9,255	$ 5.90	$ 54,565
Share repurchase program	440,666	$ 5.51	2,428,792
Total	449,921	$ 5.52	$ 2,483,357

Expected Tax Treatment of Dividends

For the fiscal year ended June 30, 2020, all common stock dividends for that fiscal year were treated for tax purposes as qualified dividend income to the recipients. Based on our current projections for the fiscal year ended June 30, 2021, we expect all common stock dividends for such period to be treated as qualified dividend income to the recipients.

Note 11—Stock-Based Incentive Plan

The Evolution Petroleum Corporation 2016 Equity Incentive Plan ("2016 Plan"), approved in the December 2016 annual meeting, authorized the issuance of 1,100,000 shares of common stock prior to its expiration on December 8, 2026. Incentives under the 2016 Plan may be granted to employees, directors, and consultants of the Company in any one or a combination of the following forms: incentive stock options and non-statutory stock options, stock appreciation rights, restricted stock awards and restricted stock unit awards, performance share awards, performance cash awards, and other forms of incentives valued in whole or in part by reference to, or otherwise based on, our common stock, including its appreciation in value. On December 9, 2020, an amendment to the 2016 Plan was approved by our stockholders which increased the number of shares available for issuance by 2,500,000 shares. There were 2,206,294 shares available for grant under the 2016 Plan as of June 30, 2021.

Restricted Stock and Contingent Restricted Stock

The Company has awarded grants of both Restricted Stock and Contingent Restricted Stock as part of its long-term incentive plan. Such grants, which expire after a maximum of four years if unvested, contain service-based, performance-based, and market-based vesting provisions. The common shares underlying the Restricted Stock grants are issued on the date of grant. Contingent Restricted Stock grants vest only upon the attainment of higher performance-based or market-based vesting thresholds and are issued only upon vesting. Shares underlying Contingent Restricted Stock awards are reserved from the Plan they were granted under.

During the year ended June 30, 2021, the Company granted 314,955 service-based restricted stock awards primarily to employees under its long term incentive program together with annual awards to its directors. In addition, under this program, the Company granted 246,160 market-based restricted stock awards and 123,080 Contingent Restricted Stock awards to employees. In addition to the foregoing, in connection with the retirement of the Company's former Chief Financial Officer, vesting was accelerated as to 50,524 aggregate shares of service- and market-based equity awards (with a weighted average fair value of $5.15 per share) which, for accounting purposes, was treated as a cancellation and replacement of the same number of awards which had a fair value of $2.79 per share.

During the year ended June 30, 2020, the Chief Executive Officer upon his July 2019 employment received 48,872 shares of service-based restricted common stock which vests in three equal amounts on June 30, 2020, 2021, and 2022; he was also awarded a total of 200,000 market-based Contingent Restricted Stock units consisting of four equal tranches, each of which may vest only if its respective stock price requirement is met before the award term expires. Each tranche has a separate stated price requirement and respective vesting will occur only if, before July 1, 2023, the ninety-day trailing average Company stock share price equals or exceeds its tranche price requirement. We also granted 52,119 service-based and 104,236 market-based Restricted Stock awards to our employees as well as 56,395 serviced-based awards to the company's directors.

Service-based awards vest with continuous employment by the Company, generally in annual installments over terms of three to four years. Awards to the Company's directors have one-year cliff vesting. Restricted Stock grants, which vest based on service, are valued at the fair market value of the Company's common stock on the date of grant and amortized over the service period.

Performance-based grants vest upon the attainment of earnings, revenue, and other operational goals and require that the recipient remain an employee or director of the Company through the vesting date. The Company recognizes compensation expense for performance-based awards ratably over the expected vesting period based on the grant date fair value of the Company's common stock and when it is deemed probable, for accounting purposes, that the performance criteria will be achieved. The expected vesting period may be deemed to be shorter than the term of the award. As of June 30, 2021, there were no performance-based awards outstanding.

Many of our past market-based awards could vest if their respective two- or three-year trailing total returns on the Company's common stock exceed the corresponding total returns of various quartiles of indices consisting of peer companies. Additionally, more recent market-based awards vest when the average of the Company's closing stock price over a defined quarterly measurement period meets or exceeds a required stock price. The third-party independent assessment of fair values and expected vesting periods of these awards are determined using a Monte Carlo simulation based on the historical volatility of the Company's total return compared to the historical volatilities of the other companies in the index. Compensation expense for market-based awards is recognized over the expected vesting period using the straight-line method, so long as the holder remains an employee or director of the Company. Total compensation expense is based on the fair value of the awards at the date of grant and is independent of vesting or expiration of the awards, except for termination of service.

For market-based awards granted during the years ended June 30, 2021 and 2020, the assumptions used in the Monte Carlo simulation valuations, expected lives and fair values were as follows:

	Year Ended June 30, 2021	2020
Weighted average fair value of market-based awards granted	$ 3.08	$ 3.79
Risk-free interest rate	0.23 %	1.65% to 1.87%
Expected life in years	2.56	1.35 to 2.56
Expected volatility	56.9 %	38.6% to 43.7%
Dividend yield	3.2 %	6% to 7.2%

Unvested Restricted Stock awards at June 30, 2021 consisted of the following:

Award Type	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Service-based awards	348,762	$ 3.37
Market-based awards	320,533	3.38
Unvested at June 30, 2021	669,295	$ 3.37

The following table sets forth the Restricted Stock transactions for the year ended June 30, 2021:

	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2021	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2020	285,028	$ 5.53	$ —	
Service-based shares granted	365,479	2.97		
Market-based shares granted	246,160	3.07		
Vested	(176,848)	5.09		
Forfeited	(50,524)	5.15		
Unvested at June 30, 2021	669,295	$ 3.37	$ 1,530,550	1.88

The following is a summary of Restricted Stock that vested during the last two fiscal years:

	Year Ended June 30, 2021	2020
Vesting-date intrinsic value of Restricted Stock	$ 570,711	$ 477,647
Grant-date fair value of vested Restricted Stock	$ 900,007	$ 748,893
Number of awards that vested	176,848	104,159

Unvested Contingent Restricted stock awards table below consists solely of market-based awards for the year ended June 30, 2021:

	Number of Restricted Stock Units	Weighted Average Grant-Date Fair Value	Unamortized Compensation Expense at June 30, 2021	Weighted Average Remaining Amortization Period (Years)
Unvested at July 1, 2020	200,000	$ 3.50		
Market-based awards granted	123,080	1.76		
Vested	—	—		
Unvested at June 30, 2021	323,080	$ 2.84	$ 169,257	2.00

All of these outstanding awards at June 30, 2021 are market-based awards.

The following is a summary of Contingent Restricted Stock vestings for the last two fiscal years:

	Year Ended June 30, 2021	2020
Vest-date intrinsic value of Contingent Restricted Stock	$ —	$ 60,225
Grant-date fair value of vested Contingent Restricted Stock	$ —	$ 34,734
Number of awards that vested	—	10,156

Stock-based Compensation Expense

For the years ended June 30, 2021, and 2020, we recognized stock-based compensation expense related to Restricted Stock and Contingent Restricted Stock grants of $1,257,684 and $1,285,663, respectively.

Note 12 – Supplemental Disclosure of Cash Flow Information

	June 30, 2021	2020
Interest paid on the Senior Secured Credit Facility	$ 86,347	$ 76,390
Income taxes paid	757,963	1,241,538
Income tax refunds	141,848	—
Non-cash transactions:		
Decrease in accrued purchases of property and equipment	80,008	(212,456)
Oil and natural gas property costs attributable to the recognition of asset retirement obligations	2,883,426	918,137

Note 13 – Income Taxes

We file a consolidated federal income tax return in the United States of America in addition to various combined and separate filings in several state and local jurisdictions.

There were no unrecognized tax benefits, nor any accrued interest or penalties associated with unrecognized tax benefits during the years ended June 30, 2021 and 2020. 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 federal and state income tax returns are open to audit under the statute of limitations for the years ended June 30, 2017 through June 30, 2020 for federal tax purposes and for the years ended June 30, 2016 through June 30, 2020 for state tax purposes. To the extent we utilize net operating losses generated in earlier years, such earlier years may also be subject to audit.

The components of our income tax provision (benefit) are as follows:

	June 30, 2021	June 30, 2020
Current:		
Federal	$ (334,473)	$ (2,264,850)
State	454,033	345,522
Total current income tax provision (benefit)	119,560	(1,919,328)
Deferred:		
Federal	(3,987,211)	(266,482)
State	(1,116,610)	4,814
Total deferred income tax provision (benefit)	(5,103,821)	(261,668)
Total income tax provision (benefit)	$ (4,984,261)	$ (2,180,996)

For the years ended June 30, 2021 and 2020, respectively, we recognized an income tax benefit of $5.0 million and an income tax benefit of $2.2 million reflecting corresponding effective tax rates of 23.3% and (58.1)%, respectively. During the fiscal 2020 year we undertook a project to seek potential cash tax savings opportunities identifying available Enhanced Oil Recovery credits ("EOR credits") related to our interests in the Delhi field. To take advantage of the EOR credits, we amended federal and state tax returns for the years ended June 30, 2017 and 2018 and incorporated the associated impacts into our 2019 tax returns. Principally as a result of the EOR credits, the Company recorded a net tax benefit of $2.8 million during fiscal 2020. Relative to the foregoing, the Company has a $3.1 million receivable for income tax refunds at June 30, 2021, which the Company currently anticipates to receive in the next twelve months based on inquiries and communication with the IRS, although no assurances can be made as to the actual date of receipt. During fiscal 2021, we recognized an income tax benefit of $0.3 million attributable to the EOR credit.

Our effective tax rate will typically differ from the statutory federal rate as a result of state income taxes, primarily in the State of Louisiana, and differences related to percentage depletion in excess of basis, stock-based compensation, valuation allowance on deferred tax assets, and other permanent differences. The following table presents the reconciliation of our income taxes calculated at the statutory federal tax rate to the income tax provision (benefit) in our financial statements.

	June 30, 2021	% of Income Before Income Taxes	June 30, 2020	% of Income Before Income Taxes
Income tax provision (benefit) computed at the statutory federal rate:	$ (4,498,661)	21.0 %	$ 788,776	21.0 %
Reconciling items:				
Return to provision adjustments	20,036	(0.1)%	(2,823,527)	(75.2)%
Depletion in excess of tax basis	(175,840)	0.8 %	(412,215)	(11.0)%
State income taxes, net of federal tax benefit	(523,436)	2.4 %	272,962	7.3 %
Permanent differences related to stock-based compensation and other	55,278	(0.3)%	22,408	0.6 %
Federal valuation allowance	570,064	(2.7)%	—	— %
EOR credit benefit	(335,717)	1.6 %	—	— %
Other	(95,985)	0.6 %	(29,400)	(0.8)%
Income tax provision (benefit)	$ (4,984,261)	23.3 %	$ (2,180,996)	(58.1)%

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.

	Asset (Liability)	
	June 30, 2021	June 30, 2020
Deferred tax assets:		
Non-qualified stock-based compensation	$ 309,671	$ 234,559
Net operating loss carry-forwards and other carry-forwards	365,279	78,197
Derivative losses	—	401,382
Asset retirement obligations (a)	1,284,907	650,042
Other deferred tax assets	160,313	53,159
Gross deferred tax assets	2,120,170	1,417,339
Valuation allowance	(861,838)	(53,218)
Net deferred tax assets	1,258,332	1,364,121
Deferred tax liability:		
Oil and natural gas properties (a)	(7,215,534)	(12,425,144)
Total deferred tax liability	(7,215,534)	(12,425,144)
Net deferred tax liability	$ (5,957,202)	$ (11,061,023)

(a) Certain deferred tax assets related to asset retirement obligations have been reclassified from the June 30, 2020 oil and natural gas properties deferred tax liability balance in order to conform to the current year presentation.

As of June 30, 2021, we had a federal tax loss carryforward of approximately $0.6 million that we acquired through a reverse merger in May 2004. The majority of the tax loss carryforwards from the reverse merger expired without being utilized. We will be able to utilize a maximum of $0.2 million of these carryforwards in equal annual amounts of $39,648 through 2023 and the balance is not able to be utilized based on the provisions of Internal Revenue Code ("IRC") Section 382. We have recorded a valuation allowance for the portion of our net operating loss that is limited by IRC Section 382.

In addition, we must assess the likelihood that we will be able to realize our deferred tax assets. Realization is dependent on generating sufficient taxable income over the period the deferred tax assets are deductible. Given the Company is in a cumulative loss position, Management considered the reversal of deferred tax liabilities and tax planning strategies in making the assessment of the realization of deferred tax assets. Based upon the weight of available evidence, the Company believes that some of the deferred tax assets are not likely to be realized at the time of this report and have recorded an increase in the valuation allowance during the current year related to the federal and state deferred tax assets of $0.6 million and $0.2 million respectively.

Note 14 – Earnings (Loss) per Common Share

The following table sets forth the computation of basic and diluted net income per share:

	June 30,	
	2021	2020
Numerator		
Net income (loss) attributable to common stockholders	$ (16,437,934)	$ 5,937,072
Denominator		
Weighted average number of common shares – Basic	33,263,701	33,031,149
Effect of dilutive securities:		
Contingent restricted stock grants	—	1,942
Weighted average number of common shares and dilutive potential common shares used in diluted earnings (loss) per share	33,263,701	33,033,091
Net earnings (loss) per common share – Basic	$ (0.49)	$ 0.18
Net earnings (loss) per common share – Diluted	$ (0.49)	$ 0.18

Outstanding Potentially Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2021
Contingent Restricted Stock grants	$ —	323,080

Outstanding Potential Dilutive Securities	Weighted Average Exercise Price	Outstanding at June 30, 2020
Contingent Restricted Stock grants	$ —	200,000

Note 15 – Senior Secured Credit Agreement

On April 11, 2016, the Company entered into a three-year, senior secured reserve-based credit facility (the "Senior Secured Credit Facility") in an amount up to $50 million. On May 25, 2018, we entered into the third amendment to our credit agreement governing the Facility to, among other things, extend the maturity date to April 11, 2021. On December 31, 2018, we entered into the fourth amendment to our credit agreement governing the Senior Secured Credit Facility to broaden the definition for the Use of Proceeds.

Under the Senior Secured Credit Facility the borrowing base is redetermined semiannually. On November 2, 2020, the Company completed its Fall redetermination of the Senior Secured Credit Facility, resulting in a borrowing base of $23 million, and entered into the fifth amendment to the Senior Secured Credit Facility extending the maturity to April 9, 2024.

On January 5, 2021 and effective as of December 28, 2020, we entered into the sixth amendment of our Senior Secured Credit Facility which replaced the Debt Service Coverage Ratio (as defined therein) maintenance covenant with a new covenant requiring Current Ratio (as defined therein) of not less than 1.00 to 1.00.

On March 30, 2021, the Company completed its spring redetermination of the Senior Secured Credit Facility, resulting in a borrowing base increase to $30 million.

On August 5, 2021, and effective as of June 30, 2021, we entered into the seventh amendment of our Senior Secured Credit Facility which added definitions for the terms "Acquired Entity or Mineral Interests" and "Acquired Entity or Mineral Interests EBITDA Adjustment." Additionally, the Consolidated Tangible Net Worth was reduced to $40 million from $50 million.

We were in compliance with all financial covenants and there was $4 million outstanding under the Senior Secured Credit Facility at June 30, 2021 which is secured by substantially all of the Company's assets.

Borrowings from the Senior Secured Credit Facility may be used for the acquisition and development of oil and natural gas properties, investments in cash flow generating assets complimentary to the production of oil and natural gas, and for letters of credit and other general corporate purposes.

The Senior Secured Credit Facility included a placement fee of 0.50% on the initial borrowing base amounting to $50,000,000 and carries a commitment fee of 0.25% per annum on the undrawn portion of the borrowing base. Any borrowings under the Senior Secured Credit Facility will bear interest, at the Company's option, at either LIBOR plus 2.75%, subject to a minimum LIBOR of 0.25%, or the Prime Rate, as defined under the Senior Secured Credit Facility, plus 1.00%. The Senior Secured Credit Facility contains financial covenants including a requirement that the Company maintain, as of the last day of each fiscal quarter, (a) a maximum total leverage ratio of not more than 3.00 to 1.00, (b) a current ratio of not less than 1.00 to 1.00, and (c) a consolidated tangible net worth of not less than $40 million, all as defined under the Senior Secured Credit Facility.

In connection with the Senior Secured Credit Facility, the Company has incurred $168,972 of past debt issuance costs. Such costs were capitalized in "Other assets, net" and have been completely amortized to expense as of June 30, 2021.

Note 16 – Commitments and Contingencies

We are subject to various claims and contingencies in the normal course of business. In addition, from time to time, we receive communications from government or regulatory agencies concerning investigations or allegations of noncompliance with laws or regulations in jurisdictions in which we operate. At a minimum, we disclose such matters if we believe it is reasonably possible that a future event or events will confirm a material loss through impairment of an asset or the incurrence of a liability. We accrue a material loss if we believe it is probable that a future event or events will confirm a loss, we can reasonably estimate such loss, and we do not accrue future legal costs related to that loss. Furthermore, we will disclose any matter that is

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

unasserted if we consider it probable that a claim will be asserted and there is a reasonable possibility that the outcome will be unfavorable and material in amount. We expense legal defense costs as they are incurred.

Note 17 – Concentrations of Credit Risk

Major Customers. As a non-operator, we presently market our production through the field operators. The majority of our natural gas, oil, and condensate production is sold to purchasers under short-term (less than 12 months) contracts at market-based prices. The following table identifies customers from whom we derived 10 percent or more of our net oil and natural gas revenues during the years ended June 30, 2021 and 2020. The loss of either one of our oil purchasers or disruption to their respective pipelines could adversely affect our net realized pricing and potentially our near-term production levels. The loss of our NGL purchaser, who trucks NGLs from the field, would not be expected to have a material adverse effect on our operations.

	Year Ended June 30,	
Customer	2021	2020
Plains Marketing L.P. (Delhi field oil)	62 %	87 %
Merit Energy Company (Hamilton Dome field oil)	19 %	10 %
All others	19 %	3 %
Total	100 %	100 %

Accounts Receivable. Substantially all of our accounts receivable from field operators result from oil and natural gas sales to third-parties in the oil and natural gas industry. Our concentration of customers in this industry may impact our overall credit risk.

Cash and Cash Equivalents. We are subject to concentrations of credit risk with respect to our cash and cash equivalents, which we attempt to minimize by maintaining our cash and cash equivalents in high quality money market funds. At times, cash balances may exceed limits federally insured by the Federal Deposit Insurance Corporation ("FDIC").

Note 18 – Derivatives

It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial or commodity hedging institutions deemed by management as competent and competitive market makers. As of June 30, 2021, the Company did not have any remaining open derivative contracts.

The Company has in the past and may utilize in the future fixed-price swaps or costless put/call collars to hedge a portion of its anticipated future production. Fixed-price swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for the volumes under contract. A costless collar consists of a sold call, which establishes a maximum price the Company will receive for the volumes under contract, and a purchased put that establishes a minimum price. The Company has elected not to designate its open derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of the derivative contracts and all payments and receipts on settled derivative contracts in "Net (gain) loss on derivative contracts" on the consolidated statements of operations.

	Years Ended June 30,	
	2021	2020
Realized (gain) loss	$ 2,525,988	$ (528,139)
Unrealized (gain) loss	(1,911,343)	1,911,343
Net (gain) loss on derivative contracts	$ 614,645	$ 1,383,204

The Company's derivative contract is recorded at fair market value and is included in the consolidated balance sheets as an asset or a liability. The Company did not have any open positions as of June 30, 2021.

The following sets forth a summary of the Company's oil derivative positions during the year ended June 30, 2021.

Period	Type of Contract	Volumes in Barrels	Price / Price Range	Weighted Average Floor Price per Bbl.	Weighted Average Ceiling Price per Bbl.
July 2020 to December 2020	Fixed-Price Swap	257,600	$32	$32	$—

The Company nets its derivative instrument fair value amounts executed with the same counterparty. The Company enters into an ISDA with each counterparty prior to a derivative contract with such counterparty. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency.

Note 19 – Fair Value Measurement

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

The three levels are defined as follows:

Level 1—Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2—Other inputs that are observable directly or indirectly, such as quoted prices in markets that are not active or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3—Unobservable inputs for which there are little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Fair Value of Derivative Instruments. The Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. ASC 820 – Fair Value Measurement ("ASC 820") establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs are generally market corroborated (Level 2), and the Company classifies fair value balances as such. There were no open positions as of June 30, 2021, and there were $1.9 million of open positions as of June 30, 2020 which were all settled during the current fiscal year.

As required by ASC 820, a financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment; this may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between fair value hierarchy levels for any period presented in this report. The Company did not have any open positions as of June 30, 2021.

Other Fair Value Measurements. The initial measurement and any subsequent revision of asset retirement obligations at fair value are calculated using discounted future cash flows of internally estimated costs. Significant Level 3 inputs used in the calculation of asset retirement obligations include the costs of plugging and abandoning wells, surface restoration, and reserve lives. Subsequent to initial recognition, revisions to estimated asset retirement obligations are made when changes occur for input values.

Note 20 – Supplemental Disclosures about Oil and Natural Gas Producing Properties (unaudited)

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 property 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, examining specific areas that are considered to have prospects containing oil and natural gas reserves, costs of drilling exploratory wells, geologic and geophysical assessment costs, and carrying costs on undeveloped properties. Development costs are incurred to obtain access to proved reserves, including the cost of drilling. Development costs also include amounts incurred due to the recognition of asset retirement obligations of $2,883,426 and $918,137 during the years ended June 30, 2021 and 2020, respectively.

	For the Years Ended June 30,	
	2021	2020
Oil and Natural Gas Activities		
Property acquisition costs:		
Proved property	$ 18,297,013	$ 9,337,716
Unproved property	—	—
Exploration costs	—	—
Development costs	3,435,836	2,430,510
Total costs incurred for oil and natural gas activities	$ 21,732,849	$ 11,768,226

Estimated Net Quantities of Proved Oil and Natural Gas Reserves

The following estimates of the net proved oil and natural gas reserves of our oil and gas properties located entirely within the United States of America are based on evaluations prepared by third-party reservoir engineers, D&M. Reserve volumes and values were determined under the method prescribed by the SEC for our fiscal years ended June 30, 2021 and 2020. SEC methodology requires the application of the previous 12 months unweighted arithmetic average first-day-of-the-month price, and current costs held constant throughout the projected reserve life, when estimating whether reserve quantities are economical to produce.

Proved oil and natural gas reserves are estimated quantities of oil, natural gas, and natural gas liquids that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. There are uncertainties inherent in estimating quantities of proved oil and natural gas reserves, projecting future production rates, and timing of development expenditures. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Estimated quantities of proved oil, natural gas, and natural gas liquids reserves and changes in quantities of proved developed and undeveloped reserves for each of the periods indicated are as follows:

	Oil (Bbls)	NGLs (Bbls)	Natural Gas (Mcf)	BOE
Proved developed and undeveloped reserves:				
June 30, 2019	7,615,731	1,364,761	—	8,980,492
Revisions of previous estimates (a)	(2,177,787)	734,169	—	(1,443,618)
Improved recovery, extensions and discoveries	—	—	—	—
Sales of minerals in place	—	—	—	—
Purchase of reserves in place (c)	3,426,756	—		3,426,756
Production (sales volumes)	(638,464)	(106,340)	—	(744,804)
June 30, 2020	8,226,236	1,992,590	—	10,218,826
Revisions of previous estimates (b)	661,711	93,139	330	754,905
Improved recovery, extensions and discoveries	—	—	—	—
Purchase of reserves in place (c)	86,608	4,957,226	49,533,801	13,299,468
Sales of minerals in place	—	—	—	—
Production (sales volumes)	(554,888)	(171,451)	(963,496)	(886,922)
June 30, 2021	8,419,667	6,871,504	48,570,635	23,386,277
Proved developed reserves:				
June 30, 2019	6,273,907	1,124,302	—	7,398,209
June 30, 2020	6,577,731	1,777,236	—	8,354,967
June 30, 2021	6,815,126	6,662,952	48,570,634	21,573,184
Proved undeveloped reserves:				
June 30, 2019	1,341,824	240,459	—	1,582,283
June 30, 2020	1,648,505	215,354	—	1,863,859
June 30, 2021	1,604,541	208,551	—	1,813,092

(a) Revisions in fiscal year 2020 were primarily due to negative revisions at Hamilton Dome field reflecting the impact of pricing on future economic production. In March 2020 when the oil price decreased, the operator began to shut-in wells that were not economic at those lower prices to try and keep the field cash flow positive. The use of an SEC price deck for our reserves at June 30, 2020, precludes volumes that are uneconomic at such prices. Positive NGL revisions at Delhi field reflect adjusted methodology of forecasting NGLs independently from the oil production as forecasted by our independent reservoir engineering firm.

(b) Revisions in fiscal year 2021 were primarily due to positive revisions at Hamilton Dome reflecting the impact of increased oil pricing in the field on future production and extension of reserves economic limit. Positive NGL revisions at Delhi field reflect the impact of increased pricing on future production and the extension of reserves economic limit. Positive natural gas revisions in the Barnett Shale reflect the impact of increased natural gas prices from the date of the Barnett Shale Acquisition on May 7, 2021 to the end of the fiscal year on June 30, 2021.

(c) On May 7, 2021, the Company acquired the Barnett Shale assets from Tokyo Gas Americas for $18.3 million, net of preliminary purchase price adjustments. On November 1, 2019, the Company acquired certain mineral interests in the Hamilton Dome field from Merit, who owns the vast majority of the remaining working interest in the field.

Standardized Measure of Discounted Future Net Cash Flows

Future oil and natural gas sales, production, and development costs have been estimated using prices and costs in effect at the end of the years indicated, as required by ASC 932, Extractive Activities - Oil and Gas ("ASC 932"). ASC 932 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing our proved oil and natural gas reserves and for asset retirement obligations, assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to our proved oil and natural gas reserves, less the tax basis of the related properties. The future income tax expenses do not give effect to tax credits, allowances, or the

EVOLUTION PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

impact of general and administrative costs of ongoing operations relating to the Company's proved oil and natural gas reserves. Changes in the demand for oil and natural gas, inflation, and other factors make such estimates inherently imprecise and subject to substantial revision. The table below should not be construed to be an estimate of the current market value of our proved reserves.

The standardized measure of discounted future net cash flows related to proved oil and natural gas reserves as of June 30, 2021 and 2020 are as follows:

	As of June 30, 2021	2020
Future cash inflows	$ 632,620,246	$ 399,358,481
Future production costs and severance taxes	(398,021,728)	(240,399,715)
Future development costs	(29,339,399)	(24,623,426)
Future income tax expenses	(42,368,085)	(21,982,469)
Future net cash flows	162,891,034	112,352,871
10% annual discount for estimated timing of cash flows	(75,308,483)	(49,862,035)
Standardized measure of discounted future net cash flows	$ 87,582,551	$ 62,490,836

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the previous 12 months unweighted arithmetic average first-day-of-the-month commodity prices for each year and reflect adjustments for lease quality, transportation fees, energy content, and regional price differentials.

	For the Years Ended June 30, 2021		2020	
	Oil (Bbl)	Gas (MMBtu)	Oil (Bbl)	Gas (MMBtu)
NYMEX prices used in determining future cash flows	$ 49.72	$ 2.46	$ 47.37	n/a

There were no natural gas reserves in 2020. The NGL prices utilized for future cash inflows were based on historical prices received, where available. For the Delhi NGL plant, we utilized historical prices for the expected mix and net pricing of natural gas liquid products projected to be produced by the plant.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved oil, natural gas, and natural gas liquids reserves is as follows:

	For the Years Ended June 30, 2021	2020
Balance, beginning of the fiscal year	$ 62,490,836	$ 126,732,042
Net changes in sales prices and production costs related to future production	11,538,209	(83,857,342)
Changes in estimated future development costs	403,109	(4,099,792)
Sales of oil and gas produced during the period, net of production costs	(16,115,302)	(16,093,794)
Net change due to extensions, discoveries, and improved recovery	—	—
Net change due to revisions in quantity estimates	6,840,767	(6,746,316)
Net change due to purchase of minerals in place	31,461,405	10,364,875
Development costs incurred during the period	—	1,431,444
Accretion of discount	7,529,289	16,266,663
Net change in discounted income taxes	(10,678,450)	17,078,591
Net changes in timing of production and other	(5,887,312)	1,414,465
Balance, end of the fiscal year	$ 87,582,551	$ 62,490,836

Note 21 – Selected Quarterly Financial Data (Unaudited)

2021	First (a)	Second (b)	Third	Fourth (c)
Revenues	$ 5,595,376	$ 5,768,152	$ 7,635,748	$ 13,703,078
Income (loss) from operations	$ (9,429,720)	$ (15,910,266)	$ 980,605	$ 3,000,750
Net income (loss) attributable to common shareholders	$ (7,135,148)	$ (12,710,007)	$ 1,191,001	$ 2,216,220
Basic earnings (loss) per common share	$ (0.22)	$ (0.38)	$ 0.04	$ 0.07
Diluted earnings (loss) per common share	$ (0.22)	$ (0.38)	$ 0.04	$ 0.07

2020	First	Second	Third (d)	Fourth
Revenues	$ 9,152,215	$ 9,381,615	$ 7,712,619	$ 3,352,847
Income (loss) from operations	$ 3,274,019	$ 2,249,764	$ 951,814	$ (2,786,164)
Net income (loss) attributable to common shareholders	$ 2,792,820	$ 1,764,918	$ 3,710,159	$ (2,330,825)
Basic earnings per common share	$ 0.08	$ 0.05	$ 0.11	$ (0.07)
Diluted earnings per common share	$ 0.08	$ 0.05	$ 0.11	$ (0.07)

(a) The first quarter of fiscal 2021 included a ceiling test impairment charge of $9.6 million.

(b) The second quarter of fiscal 2021 included a ceiling test impairment charge of $15.2 million.

(c) The fourth quarter of fiscal 2021 includes approximately two months of production and related revenues and expenses from the Barnett Shale assets.

(d) The third quarter of fiscal 2020 was impacted by a $2.8 million tax benefit attributable to the EOR tax credits.

Note 22 – Subsequent Events

On August 5, 2021, and effective as of June 30, 2021, we entered into the seventh amendment of our Senior Secured Credit Facility which added definitions for the terms "Acquired Entity or Mineral Interests" and "Acquired Entity or Mineral Interests EBITDA Adjustment." Additionally, the Consolidated Tangible Net Worth was reduced to $40 million from $50 million.

On September 9, 2021, the Company declared a quarterly cash dividend of $0.075 per share of common stock to shareholders of record on September 20, 2021 and payable on September 30, 2021.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; this information is accumulated and communicated to this Company's management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow for timely decisions regarding required disclosure.

As required by Securities and Exchange Commission Rule 13a-15(b), we carried out an evaluation, under the supervision and with the participation of the Company's management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that the information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

Management's Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the Company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Generally accepted accounting principles include those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, an evaluation was conducted on the effectiveness of the Company's internal control over financial reporting based on criteria established in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Management concluded that the Company maintained effective internal control over financial reporting as of June 30, 2021.

Effective April 27, 2020, the SEC adopted certain amendments to the accelerated filer and large accelerated filer definitions to more appropriately tailor the types of issuers that are included in the categories of accelerated and large accelerated filers and to promote capital formation, preserve capital, and reduce unnecessary burdens for certain smaller issuers while maintaining investor protections. As a result of the amendments, certain low-revenue issuers will remain obligated, among other things, to establish and maintain internal control over financial reporting and have management assess the effectiveness of its internal control over financial reporting, but they will not be required to have their management's assessment of the effectiveness of internal controls over financial reporting attested to and reported on by an independent auditor. As a result, the effectiveness of our internal control over financial reporting at June 30, 2021 has not been audited by Moss Adams LLP, the independent registered public accounting firm that also audited our financial statements.

Changes in Internal Control Over Financial Reporting

There has been no change in the Company's internal control over financial reporting during the fourth quarter ended June 30, 2021 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

On August 11, 2021, Mr. Roderick Schultz and the Board agreed to terms of his retirement as the Chief Accounting Officer and Senior Vice President of the Company effective August 2, 2021. In connection with Mr. Schultz's retirement, the Board has appointed Mr. Ryan Stash as the Principal Accounting Officer of the Company to replace Mr. Schultz effective September 9, 2021.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2021 fiscal year.

Item 11. Executive Compensation

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2021 fiscal year.

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

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2021 fiscal year.

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

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2021 fiscal year.

Item 14. Principal Accountant Fees and Services

Incorporated by reference to the Company's Proxy Statement to be filed with the Commission pursuant to Regulation 14A within 120 days of the end of the Company's 2021 fiscal year.

PART IV.

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as part of this report:

1. **Financial Statements.**

   Our consolidated financial statements are included in Part II, Item 8 of this report:

   Report of Independent Registered Public Accounting Firm

   Consolidated Balance Sheets

   Consolidated Statements of Operations

   Consolidated Statements of Cash Flows

   Consolidated Statements of Changes in Stockholders' Equity

   Notes to the Consolidated Financial Statements

2. **Financial Statements Schedules and Supplementary Information Required to be Submitted:**

   None.

3. **Exhibits**

   A list of the exhibits filed or furnished with this report on Form 10-K (or incorporated by reference to exhibits previously filed or furnished by us) is provided in the Master Exhibit Index of this report. Those exhibits incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. Otherwise, the exhibits are filed herewith.

Item 16. Form 10-K Summary

None.

SIGNATURES

In accordance with Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized in the City of Houston, Texas, on the date indicated.

Evolution Petroleum Corporation

Date: September 14, 2021

By: /s/ JASON E. BROWN
Jason E. Brown
President and Chief Executive Officer
(Principal Executive Officer)

In accordance with the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Date	Signature	Title
September 14, 2021	/s/ ROBERT S. HERLIN Robert S. Herlin	Chairman of the Board
September 14, 2021	/s/ JASON E. BROWN Jason E. Brown	President and Chief Executive Officer (Principal Executive Officer)
September 14, 2021	/s/ RYAN STASH Ryan Stash	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer and Principal Accounting Officer)
September 14, 2021	/s/ EDWARD J. DIPAOLO Edward J. DiPaolo	Lead Director
September 14, 2021	/s/ WILLIAM DOZIER William Dozier	Director
September 14, 2021	/s/ KELLY W. LOYD Kelly W. Loyd	Director
September 14, 2021	/s/ MARJORIE A. HARGRAVE Marjorie A. Hargrave	Director

EXHIBIT INDEX

MASTER EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
3.1	Articles of Incorporation (previously filed as an exhibit to Form 8-K on February 7, 2002)
3.2	Certificate of Amendment to Articles of Incorporation (previously filed as an exhibit to Form 8-K on February 7, 2002)
3.3	Certificate of Amendment to Articles of Incorporation (previously filed as an exhibit to Form SB 2/A on October 19, 2005)
3.4	Certificate of Designation of Rights and Preferences for 8.5% Series A Cumulative Preferred Stock (previously filed as an exhibit to Form 8-K on June 29, 2011)
3.5	Amended Bylaws (previously filed as Exhibit 2.1 to Form 10KSB on March 31, 2004)
4.1	Specimen form of the Company's Common Stock Certificate (previously filed as an exhibit to Form S-3 on June 19, 2013)
4.2	2016 Equity Incentive Plan (previously filed as an exhibit to the Company's Form 10-Q on February 8, 2017)
4.3	Majority Voting Policy for Directors (previously filed as an exhibit to the Company's Current Report on Form 8-K on October 31, 2012)
4.4	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan (previously filed as an exhibit to Form 10-Q on February 8, 2018)
4.5	Form of Contingent Restricted Stock Agreement under 2016 Equity Incentive Plan (previously filed as an exhibit to Form 10-Q on February 8, 2018)
4.6	Form of Restricted Stock Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (previously filed as an exhibit to Form 10-K on September 13, 2019)
4.7	Form of Performance Share Unit Award Agreement under 2016 Equity Incentive Plan as Revised on July 9, 2019 (previously filed as an exhibit to Form 10-K on September 13, 2019)
10.1	Settlement Agreement, dated June 24, 2016, by and among Denbury Onshore, LLC, Denbury Inc., NGS Sub Corp., Tertiaire Resources Company, and the Company (previously filed as an exhibit to Form 10-K on September 9, 2016)
10.2	Form of Indemnification Agreement for Officers and Directors, as adopted on September 20, 2006 (previously filed as an exhibit to Form 8-K on September 22, 2006)
10.3	Credit Agreement dated April 11, 2016 between Evolution Petroleum Corporation and MidFirst Bank (previously filed as an exhibit to Form 8-K on April 15, 2016)
10.4	First Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective October 18, 2016 (previously filed as an exhibit to Form 10-Q on November 9, 2016)
10.5	Second Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective February 1, 2018 (previously filed as an exhibit to Form 10-Q on February 8, 2018)
10.6	Third Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective May 25, 2018 (previously filed on September 10, 2018 as an exhibit to Form 10-K)
10.7	Fourth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective December 31, 2018 (previously filed on February 8, 2019 as an exhibit to Form 10-Q)
10.8	Fifth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective November 2, 2020 (previously filed on November 9, 2020 as an exhibit to Form 10-Q)
10.9	Sixth Amendment to Credit Agreement dated April 11, 2016, between Evolution Petroleum Corporation and MidFirst Bank effective December 28, 2020 (previously filed as an exhibit on Form 8-K filed on January 11, 2021)
10.10	Seventh Amendment to Credit Agreement dated August 5, 2021, between Evolution Petroleum Corporation and MidFirst Bank effective June 30, 2021
10.11	Employment Offer Letter to Jason E. Brown dated July 8, 2019 (previously filed as an exhibit to Form 10-K on September 13, 2019)
10.12	Employment Offer Letter to Ryan Stash dated October 9, 2020 (filed herein)
10.13	Purchase and Sale Agreement, dated March 29, 2021, between Evolution Petroleum Corporation and TG Barnett Resources LLP (incorporated by reference to Exhibit 10.1 to Evolution Petroleum Corporation’s Current Report on Form 8-K filed on May 11, 2021)
10.14	First Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective April 20, 2021 (incorporated by reference to Exhibit 10.2 to Evolution Petroleum Corporation’s Current Report on Form 8-K filed on May 11, 2021)
10.15	Second Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective May 4, 2021 (incorporated by reference to Exhibit 10.3 to Evolution Petroleum Corporation’s Current Report on Form 8-K filed on May 11, 2021)

EXHIBIT NUMBER	DESCRIPTION
10.16	Third Amendment to the Purchase and Sale Agreement, dated March 29, 2021, effective May 6, 2021 (incorporated by reference to Exhibit 10.4 to Evolution Petroleum Corporation’s Current Report on Form 8-K filed on May 11, 2021)
14.1	Code of Business Conduct and Ethics (filed herewith)
21.1	List of Subsidiaries of Evolution Petroleum Corporation (filed herein)
23.1	Consent of Moss Adams LLP (filed herein)
23.2	Consent of DeGolyer & MacNaughton (filed herein)
31.1	Certification of Chief Executive Officer Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herein)
31.2	Certification of President and Chief Financial Officer Pursuant to Rule 15D-14 of the Securities Exchange Act of 1934, as Amended as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herein)
32.1	Certification of Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein)
32.2	Certification of President and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herein)
99.1	The summary of DeGolyer and MacNaughton's Report as of June 30, 2021, on oil and gas reserves (SEC Case) dated August 2, 2021 and certificate of qualification (filed herein)
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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