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

(Mark One)

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

For the fiscal year ended February 28, 2022

☐ 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 000-50107

DAYBREAK OIL AND GAS, INC.

(Exact name of registrant as specified in its charter)

Washington	**91-0626366**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1101 N. Argonne Road, Suite A-211, Spokane Valley, WA	**99212**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: **(509) 232-7674**

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

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, $.001 par value

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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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 Act). Yes ☐ No ☑

The aggregate market value of the voting and non-voting stock held by non-affiliates of the registrant, based on the closing price of $0.035 on August 31, 2021, as reported by the OTC Pink® Open Market was $1,810,516.

At June, 14, 2022, the registrant had 384,735,402 outstanding shares of $0.001 par value common stock.

DOCUMENTS INCORPORATED BY REFERENCE:

Part III of the Form 10-K incorporates by reference certain portions of the registrant's proxy statement for its 2022 Annual Meeting of Shareholders to be filed with the Commission not later than 120 days after the end of the fiscal year covered by this report.

TABLE OF CONTENTS

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements include statements relating to future events or our future financial or operating performance, including statements regarding guidance, industry prospects or future results of operations or financial position, made in this Annual Report on Form 10-K. These forward-looking statements are based on our current expectations, assumptions, estimates and projections for the future of our business and our industry and are not statements of historical fact. Words such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "predict," "project," "will" and similar expressions identify forward-looking statements. Examples of forward-looking statements include statements about the following:

- Our future operating results;
- Our future capital expenditures;
- Our future financing;
- Our expansion and growth of operations; and
- Our future investments in and acquisitions of crude oil and natural gas properties.

We have based these forward-looking statements on assumptions and analyses made in light of our experience and our perception of historical trends, current conditions, and expected future developments. However, you should be aware that these forward-looking statements are only our predictions and we cannot guarantee any such outcomes. Future events and actual results may differ materially from the results set forth in or implied in the forward-looking statements. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- General economic and business conditions;
- National and international pandemic such as the novel coronavirus COVID-19 outbreak;
- Exposure to market risks in our financial instruments;
- Fluctuations in worldwide prices and demand for crude oil and natural gas;
- Our ability to find, acquire and develop crude oil and natural gas properties;
- Fluctuations in the levels of our crude oil and natural gas exploration and development activities;
- Changes to our reserve estimates or the recovery of crude oil and natural gas quantities that is less than our reserve estimates;
- Risks associated with crude oil and natural gas exploration and development activities;
- Competition for raw materials and customers in the crude oil and natural gas industry;
- Technological changes and developments in the crude oil and natural gas industry;
- Legislative and regulatory uncertainties, including proposed changes to federal tax law and climate change legislation, regulation of hydraulic fracturing, and potential environmental liabilities;
- Our ability to continue as a going concern;
- Our ability to secure financing under any commitments as well as additional capital to fund operations; and
- Other factors discussed elsewhere in this Form 10-K; in our other public filings and press releases; and discussions with Company management.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should any underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. These risks and uncertainties, as well as other risks and uncertainties that could cause our actual results to differ significantly from management's expectations, are described in greater detail in Item 1A of Part 1, "Risk Factors". We specifically undertake no obligation to publicly update or revise any information contained in a forward-looking statement or any forward-looking statement in its entirety, whether as a result of new information, future events, or otherwise, except as required by law.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

PART I

ITEM 1. BUSINESS

Historical Background

Daybreak Oil and Gas, Inc. (referred to herein as "we," "our," "us," "Daybreak" or the "Company") was originally incorporated in the State of Washington on March 11, 1955 as Daybreak Uranium, Inc. The Company was organized to explore for, acquire and develop mineral properties throughout the Western United States. In August 1955, we acquired the assets of Morning Sun Uranium, Inc. By the late 1950's, we ceased to be a producing mining company and thereafter engaged in mineral exploration only. In May 1964, to reflect the diversity of our mineral holdings, we changed our name to Daybreak Mines, Inc. By February 1967, we had ceased all exploration operations. After that time, our activities were confined to annual assessment and maintenance work on our Idaho mineral properties and other general and administrative functions. In November 2004, we sold our last remaining mineral rights covering approximately 340 acres in Shoshone County, Idaho.

Effective March 1, 2005, we undertook a new business direction for the Company; that of an exploration, development and production company in the crude oil and natural gas industry. In October of 2005, to better reflect this new direction of the Company, our shareholders approved changing our name to Daybreak Oil and Gas, Inc. Our Common Stock is quoted on the OTC Pink® Open Market under the symbol DBRM.

Our corporate office is located at 1101 N. Argonne Road, Suite A-211, Spokane Valley, Washington 99212-2699. Our telephone number is (509) 232-7674. Additionally, we have a regional operations office located at 1414 S. Friendswood Dr., Suite 212, Friendswood, Texas 77546. The telephone number of our office in Friendswood is (281) 996-4176.

Crude Oil and Natural Gas Overview

We are an independent crude oil and natural gas exploration, development and production company. Our basic business model is to increase shareholder value by finding and developing crude oil and natural gas reserves through exploration and development activities and selling the production from those reserves at a profit. To be successful, we must, over time, be able to find crude oil and natural gas reserves and then sell the resulting production at a price that is sufficient to cover our finding costs, operating expenses, administrative costs and interest expense, plus offer us a return on our capital investment. A secondary means of generating returns can include the sale of either producing or non-producing lease properties.

Our long-term success depends on, among many other factors, the acquisition and drilling of commercial grade crude oil and natural gas properties and on the prevailing sales price for crude oil and natural gas along with associated operating expenses. The volatile nature of the energy markets makes it difficult to estimate future prices of crude oil and natural gas; however, any prolonged period of depressed prices or market volatility, such as we have experienced since June of 2014, will and does have a material adverse effect on our results of operations and financial condition.

The Company's focus is to pursue crude oil and natural gas drilling opportunities through joint ventures with industry partners as a means of limiting our drilling risk. Prospects are generally brought to us by other crude oil and natural gas companies or individuals. We identify and evaluate prospective crude oil and natural gas properties to determine both the degree of risk and the commercial potential of the project. We seek projects that offer a mix of low risk with a potential of steady reliable revenue as well as projects with a higher risk, but that may also have a larger return.

Modern technology including 3-D seismic helps us identify potential crude oil and natural gas reservoirs and to mitigate our risk. The Company conducts all of our drilling, exploration and production activities in the United States, and all of our revenues are derived from sales to customers within the United States. We seek to maximize the value of our asset base by exploring and developing properties that have both production and reserve growth potential. Currently, our core areas of activity are located in Kern County, California and Michigan, although new opportunities may ultimately be secured in other areas.

In some instances, such as with our California crude oil operations, we strive to be the operator of our crude oil and natural gas properties. As the operator, we are more directly in control of the timing; costs of drilling and completion; and production operations on our projects. We are compensated by our other working interest partners for the additional duties performed by Daybreak as operator. In other instances, we may not serve as operator where we have concluded that the existing operator has existing operational knowledge, equipment and personnel in place, and operates competently and prudently and with the same operational goals that we would have if we served as operator. However, we have our own personnel onsite during critical operations such as drilling, fracturing and completion operations.

Known Trends and Uncertainties

As we continue to pursue our developmental drilling program in our California properties, the timing of these activities continues to be determined by current crude oil and natural gas prices; the availability of drilling funds; and in California, the length and timing of the drilling permit approval process. Additionally, our drilling programs are also very sensitive to drilling costs. We attempt to control these costs through drilling efficiencies by working with service providers to receive acceptable unit costs.

In order to continue our drilling program in California, we must be able to realize an acceptable margin between our expected cash flows from new production and the cost to drill and complete new wells. If any combination of a decrease in crude oil and natural gas prices; the availability of drilling funds; and/or, the rising costs of drilling, completion and other field services occurs in future periods, we may be forced to modify or discontinue a planned drilling program.

All of the Company's crude oil production in California is sold under contracts which are market-sensitive. Accordingly, the Company's financial condition, results of operations, and capital resources are highly dependent upon prevailing market prices of hydrocarbon prices and demand for crude oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the control of the Company. Some of these factors include the level of global demand for and price of petroleum products, foreign supply of crude oil and natural gas, the establishment of and compliance with production quotas by oil-exporting countries, the relative strength of the U.S. dollar, weather conditions, the price and availability of alternative fuels, and overall economic conditions, both foreign and domestic. Because of the size of our Company, we are highly susceptible to downward changes in the price we receive for our hydrocarbon sales especially crude oil.

California Crude Oil Prices

The price we receive for crude oil sales in California is based on prices posted for Midway-Sunset crude oil delivery contracts, less deductions that vary by grade of crude oil sold and transportation costs. The posted Midway-Sunset price generally moves in correlation to, and at a discount to, prices quoted on the New York Mercantile Exchange ("NYMEX") for spot West Texas Intermediate ("WTI") Cushing, Oklahoma delivery contracts. We do not currently have any natural gas revenues.

There continues to be a significant amount of volatility in hydrocarbon prices and a corresponding fluctuation in our realized sale price of crude oil does exist. An example of this is that in June of 2014 the monthly average price of WTI oil was $105.79 per barrel and our realized price per barrel of crude oil was $98.78 while in April 2020, the monthly average price of WTI crude oil was $16.55 and our monthly realized price was $16.96 per barrel. Finally, in February 2022, the monthly average price of WTI oil was $91.64 per barrel and our realized price per barrel of crude oil was $87.41. Any downward volatility in the price of crude oil will have a substantial negative impact on our profitability and cash flow from our producing California properties. It is beyond our ability to accurately predict crude oil prices over any substantial length of time. There are many factors beyond our control that influence the price we receive on our crude oil sales.

A comparison of the average WTI price and average realized crude oil sales price at our East Slope Project in California for the twelve months ended February 28, 2022 and February 28, 2021 is shown in the table below:

	Twelve Months Ended		
	February 28, 2022	**February 28, 2021**	**Percentage Change**
Average twelve month WTI crude oil price	$ 73.31	$ 39.48	85.7%
Average twelve month realized crude oil sales price (Bbl)	$ 70.75	$ 36.91	91.7%

For the twelve months ended February 28, 2022, the average WTI price was $73.31 and our average realized crude oil sale price was $70.75, representing a discount of $2.56 per barrel or 3.5% lower than the average WTI price. In comparison, for the twelve months ended February 28, 2021, the average WTI price was $39.48 and our average realized sale price was $36.91 representing a discount of $2.57 per barrel or 6.5% lower than the average WTI price. Historically, the sale price we receive for California heavy crude oil has been less than the quoted NYMEX WTI price because of the lower API gravity of our California crude oil in comparison to WTI crude oil API gravity.

California Crude Oil Revenue and Production

Crude oil revenue in California for the twelve months ended February 28, 2022 increased $275,206 or 68.0% to $680,107 in comparison to revenue of $404,901 for the twelve months ended February 28, 2021. The average sale price of a barrel of crude oil for the twelve months ended February 28, 2022 was $70.75 in comparison to $36.91 for the twelve months ended February 28, 2021. The increase of $33.84 or 91.7% per barrel in the average realized price of a barrel of crude oil accounted for 134.9% of the increase in crude oil revenue for the twelve months ended February 28, 2022.

Our net sales volume for the twelve months ended February 28, 2022 was 9,613 barrels of crude oil in comparison to 10,970 barrels sold for the twelve months ended February 28, 2021. This decrease in crude oil sales volume of 1,357 barrels or 12.4% was primarily due to fewer well days of production and the natural decline in reservoir pressure during the twelve months ended February 28, 2021.

The gravity of our produced crude oil in California ranges between 14° API and 16° API. Production for the twelve months ended February 28, 2022 was from 20 wells resulting in 7,154 well days of production in comparison to 7,288 well days of production from 20 wells for the twelve months ended February 28, 2021.

Competition

We compete with other independent crude oil and natural gas companies for exploration prospects, property acquisitions and for the equipment and labor required to operate and develop these properties. Many of our competitors have substantially greater financial and other resources than we have. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can.

We conduct all of our drilling, exploration and production activities onshore in the United States. All of our crude oil assets are located in the United States and all of our revenues are from sales to customers within the United States.

Marketing Arrangements – Principal Customer

At our East Slopes Project, located in Kern County, California, we sell all of our crude oil production to one buyer. At February 28, 2022 and February 28, 2021, this one individual customer represented 100% of crude oil sales receivable. If this local purchaser is unable to resell their products or if they lose a significant sales contract then we may incur difficulties in selling our crude oil production.

The Company's accounts receivable for California crude oil sales at February 28, 2022 and February 28, 2021 are set forth in the table below.

		February 28, 2022		February 28, 2021	
Project	**Customer**	**Accounts Receivable Crude Oil Sales**	**Percentage**	**Accounts Receivable Crude Oil Sales**	**Percentage**
California – East Slopes Project (Crude oil)	Plains Marketing	$ 117,727	100.0%	$ 108,993	100.0%

Title to Properties

As is customary in the crude oil and natural gas industry, we make only a cursory review of title to undeveloped crude oil and natural gas leases at the time we acquire them. However, before drilling operations commence, we search the title, and remedy material defects, if any, before we actually begin drilling the well. To the extent title opinions or other investigations reflect title defects, we (rather than the seller or lessor of the undeveloped property) typically are obligated to cure any such title defects at our expense. If we are unable to remedy or cure any title defects, so that it would not be prudent for us to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. Except for encumbrances we have granted as described below under "Encumbrances," we believe that we have good title to our crude oil and natural gas properties, some of which are subject to immaterial easements, and restrictions.

Regulation

The exploration and development of crude oil and natural gas properties are subject to various types of federal, state and local laws and regulations. These laws and regulations govern a wide range of matters, including the drilling and spacing of wells, hydraulic fracturing operations, allowable rates of production, restoration of surface areas, plugging and abandonment of wells and specific requirements for the operation of wells. Failure to comply with such laws and regulations can result in substantial penalties.

Laws and regulations relating to our business frequently change so we are unable to predict the future cost or impact of complying with such laws. Future laws and regulations, including changes to existing laws and regulations, could adversely affect our business. These regulatory burdens generally do not affect us any differently than they affect other companies in our industry with similar types, quantities and locations of production.

All of the states in which we operate generally require permits for drilling operations, require drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of crude oil and natural gas. Such states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of crude oil and natural gas properties, the establishment of maximum rates of production from crude oil and natural gas wells, the spacing, plugging and abandonment of such wells, restrictions on venting or flaring of natural gas and requirements regarding the ratability of production.

These laws and regulations may limit the amount of crude oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of crude oil and natural gas within their jurisdiction. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation of production, but there can be no assurance they will not do so in the future.

In California, where we currently operate a 20 well oilfield project, there is substantial federal and state regulation and oversight of produced water and its disposal. Water regulations in California are currently under review and are subject to change. We produce a substantial amount of water while lifting oil from our reservoirs. While the water we produce is considered to be “fresh water” under current testing standards and is suitable for use for livestock and agricultural purposes, its handling and use are currently under review by regional authorities. As rules change, we may be required to invest in additional water management infrastructure. There is no guarantee that we will not have to incur additional costs in the future in regards to the disposal and use of our produced water.

The California Department of Conservation Geologic Energy Management Division (CalGEM) is California's primary regulator of the oil and natural gas industry on private and state lands, with additional oversight from the State Lands Commission’s administration of state surface and mineral interests. Government actions, including the issuance of certain permits or approvals, by state and local agencies or by federal agencies may be subject to environmental reviews, respectively, under the California Environmental Quality Act (CEQA) or the National Environmental Policy Act (NEPA), which may result in delays, imposition of mitigation measures or litigation. CalGEM currently requires an operator to identify the manner in which CEQA has been satisfied prior to issuing various state permits, typically through either an environmental review or an exemption by a state or local agency.

In Kern County this requirement has typically been satisfied by complying with the local oil and gas ordinance, which was supported by an Environmental Impact Report (EIR) certified by the Kern County Board of Supervisors in 2015. A group of plaintiffs challenged the EIR and on February 25, 2020, a California Court of Appeal issued a ruling that invalidates a portion of the EIR until the County makes certain revisions to the EIR and recertifies it. On February 12, 2021, the Kern County Planning Commission voted to recommend approval of the revisions in a supplementary EIR in order to reestablish the county's oil and gas permitting system, though it must be approved by the county Board of Supervisors before becoming effective. This certification was expected to be completed in the first half of 2021; however, the supplemental EIR and certification are now in the middle of litigation. A court decision is expected sometime in 2022. After the supplementary EIR is certified, it is expected that CalGEM will rely on Kern County to serve as lead agent for CEQA purposes, reducing unnecessary delays at the state level.

The California Legislature has significantly increased the jurisdiction, duties and enforcement authority of CalGEM, the State Lands Commission and other state agencies with respect to oil and natural gas activities in recent years. For example, 2019 state legislation expanded CalGEM's duties effective on January 1, 2020 to include public health and safety and reducing or mitigating greenhouse gas emissions while meeting the state's energy needs, and will require CalGEM to study and prioritize idle wells with emissions, evaluate costs of abandonment, decommissioning and restoration, and review and update associated indemnity bond amounts from operators if warranted, up to a specified cap which may be shared among operators. Other 2019 legislation specifically addressed oil and natural gas leasing by the State Lands Commission, including imposing conditions on assignment of state leases, requiring lessees to complete abandonment and decommissioning upon the termination of state leases, and prohibiting leasing or conveyance of state lands for new oil and natural gas infrastructure that would advance production on certain federal lands such as national monuments, parks, wilderness areas and wildlife refuges.

In the event we conduct operations on federal, state or American Indian crude oil and natural gas leases, our operations may be required to comply with additional regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements and on-site security regulations, and other appropriate permits issued by the Bureau of Land Management or other relevant federal or state agencies.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state crude oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuel. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, chemical disclosure and well construction requirements on hydraulic fracturing activities. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells. We do not presently use hydraulic fracturing methods in our crude oil exploration and production in California.

Operational Hazards and Insurance

Our operations are subject to the usual hazards incident to the drilling and production of crude oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of crude oil, natural gas or well fluids, fires and pollution and other environmental risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operation. In addition, the presence of unanticipated pressures or irregularities in formations, miscalculations, or accidents may cause our drilling activities to be unsuccessful and result in a total loss of our investment.

We maintain insurance of various types to cover our operations with policy limits and retention liability customary in the industry. We believe the coverage and types of insurance we maintain are adequate. The occurrence of a significant adverse event, the risks of which are not fully covered by insurance, could have a material adverse effect on our financial condition and results of operations. We cannot give any assurances that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

Human Capital

At February 28, 2022, we had four full-time employees and two part-time employees. Additionally, we regularly use the services of four consultants on an as-needed basis for accounting, technical, oil field, geological, investor relations and administrative services. None of our employees are subject to a collective bargaining agreement. In our opinion, relations with our employees are good. We may hire more employees in the future as needed. All other services are currently contracted for with independent contractors. We have not obtained "key person" life insurance on any of our officers or directors. As we continue to manage the business ongoing, we are focused on retaining and developing our existing employees who are critical to the business.

Long-Term Success

Our long-term success depends on the successful acquisition, exploration and development of commercial grade crude oil and natural gas properties as well as the prevailing prices for crude oil and natural gas to generate future revenues and operating cash flow. Crude oil and natural gas prices are extremely volatile and are affected by many factors outside of our control. The volatile nature of the energy markets makes it difficult to estimate future prices of crude oil and natural gas; however, any prolonged period of price instability, such as was experienced from February 2020 through January 2021, has had and will likely continue to have a material adverse effect on our results of operations and financial condition. Such pricing factors are beyond our control, and have resulted and will result in negative fluctuations of our earnings. We believe; however, that even in this volatile pricing environment there are significant opportunities available to us in the crude oil and natural gas exploration and development industry.

Availability of SEC Filings

You may read and copy any materials we file with the U.S. Securities and Exchange Commission (the "SEC") at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549, on official business days during the hours of 10:00 am to 3:00 pm. You can obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address of that site is http://www.sec.gov.

Website / Available Information

Our website can be found at www.daybreakoilandgas.com. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed with or furnished to the SEC, pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 ("the Exchange Act") can be accessed free of charge on our website at www.daybreakoilandgas.com under the "Shareholder/Financial" section of our website within the "SEC Filings" subsection as soon as is reasonably practicable after we electronically file such material with, or otherwise furnish it to, the SEC.

We have adopted an Ethical Business Conduct Policy Statement to provide guidance to our directors, officers and employees on matters of business conduct and ethics, including compliance standards and procedures. We also have adopted a Code of Ethics for Senior Financial Officers that applies to our principal executive officer, principal financial officer, principal accounting officer and controller. Copies of our Ethical Business Conduct Policy Statement and Code of Ethics for Senior Financial Officers are available under the "Shareholder/Financial" section of our website at www.daybreakoilandgas.com within the heading "Corporate Governance." We intend to promptly disclose via a Current Report on Form 8-K or via an update to our website, information on any amendment to or waiver of these codes with respect to our executive officers and directors. Waiver information disclosed via the website will remain on the website for at least 12 months after the initial disclosure of a waiver.

Our Corporate Governance Guidelines and the charters of our Audit Committee, Nominating and Corporate Governance Committee, and Compensation Committee are also available in the "Shareholder/Financial" section of our website at www.daybreakoilandgas.com within the heading "Corporate Governance." In addition, copies of our Ethical Business Conduct Policy Statement, Code of Ethics for Senior Financial Officers, Corporate Governance Guidelines and the charters of the Committees referenced above are available at no cost to any shareholder who requests them by writing or telephoning us at the following address or telephone number:

Daybreak Oil and Gas, Inc.
1101 N. Argonne Road, Suite A-211
Spokane Valley, WA 99212-2699
Attention: Corporate Secretary
Telephone: (509) 232-7674

Information contained on or connected to our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

The following risk factors together with other information set forth in this Annual Report on Form 10-K, should be carefully considered by current and future investors in our securities. An investment in our securities involves substantial risks. There are many factors that affect our business, a number of which are beyond our control. Our business, financial condition and results of operations could be materially adversely affected by any of these factors. The nature of our business activities further subjects us to certain hazards and risks. The risks described below are a summary of the known material risks relating to our business. Additional risks and uncertainties not presently known to us or that we currently deem to be immaterial individually or in aggregate may also impair our business operations. If any of these risks actually occur, it could harm our business, financial condition or results of operations and impair our ability to implement our business plan or complete development projects as scheduled. In any such case, the trading price of our Common Stock could decline, and you could lose all, or a part, of your investment.

Risks Related to Volatile Energy Prices

Crude oil and natural gas prices are volatile. From January 2020 through February 2021, there was a significant period of depressed commodity prices, that significantly adversely affected, and in the future may continue to adversely affect, our financial condition, liquidity, results of operations, cash flows, access to capital markets, and ability to grow.

Our revenues, operating results, liquidity, cash flows, profitability and valuation of proved reserves depend substantially upon the market prices of crude oil and natural gas. Product prices affect our cash flow available for capital expenditures and our ability to access funds through the capital markets. Declines in commodity prices have historically adversely affected the estimated value of our proved reserves and our cash flows. The volatile nature of the energy markets makes it difficult to estimate future prices of crude oil and natural gas; however, any prolonged period of price instability, such as was experienced from February 2020 through January 2021, has had a material adverse effect on our cash flows, reserves valuation and availability of funds in the financial markets. Specifically, our average annual realized price of crude oil sales for the twelve months periods ended February 28, 2022, 2021 and February 29, 2020 was \$70.75, \$36.91 and \$60.25, respectively.

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

- changes in the supply of and demand for crude oil and natural gas;
- market uncertainty;
- the level of consumer product demands;
- hurricanes and other weather conditions;
- domestic governmental regulations and taxes;
- the foreign supply of crude oil and natural gas;
- the price of crude oil and natural gas imports
- national and international pandemics like the COVID-19; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future hydrocarbon commodity price movements with any certainty. It is beyond our control and ability to accurately predict when there will be a sustained improvement in hydrocarbon prices. All of our crude oil and natural gas sales are made pursuant to contracts based on spot market prices and are not based on long-term fixed price contracts. Crude oil and natural gas prices do not necessarily fluctuate in direct relation to each other.

The COVID-19 pandemic caused crude oil prices to decline significantly in 2020, and may adversely affect our business, results of operations and financial condition in the future.

The COVID-19 pandemic has adversely affected the global economy, and has resulted in, among other things, travel restrictions, business closures, the institution of quarantining and other mandated and self-imposed restrictions on movement and created supply chain imbalances. As a result, there was an unprecedented reduction in demand for crude oil. The decline in prices adversely affected our revenues and profitability in 2020 and, while energy prices have recovered, may adversely affect the economics of our existing wells and planned future wells. The severity, magnitude and duration of current or future COVID-19 outbreaks, the extent of actions that have been or may be taken to contain or treat their impact, and the impacts on the economy generally and oil prices in particular, are uncertain, rapidly changing and hard to predict.

Supply chain challenges arising in the wake of the COVID-19 pandemic may adversely affect our operations.

Supply and demand imbalances arising from the COVID-19 pandemic have resulted in shortages, backlogs and delayed deliveries of a wide array of products and services, including products and services critical to oil and gas operations. As a result of such supply chain challenges, we may experience unavailability, or delay in delivery, of products and services that are critical to our well operations. Any such delays may result in deferral or reduction of revenues and increased costs, any of which could materially adversely affect our profitability.

Hydrocarbon price declines may result in impairments of our asset carrying values.

Commodity prices have a significant impact on the present value of our proved reserves. Accounting rules require us to impair, as a non-cash charge to earnings, the carrying value of our crude oil and natural gas properties in certain situations. We are required to perform impairment tests on our assets periodically and whenever events or changes in circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable, and an impairment may be required. Any impairment charges we record in the future could have a material adverse effect on our results of operations in the period incurred. For the twelve months ended February 28, 2021, we determined that a non-cash impairment will not be recognized on our California crude oil properties due to the prevailing increase in the current hydrocarbon prices.

Risks Related to Our Business

To execute our business plan we will need to develop current projects and expand our operations requiring significant capital expenditures, which we may be unable to fund.

Our business plan contemplates the execution of our current exploration and development projects and the expansion of our business by identifying, acquiring, and developing additional crude oil and natural gas properties. We plan to rely on external sources of financing to meet the capital requirements associated with these activities. We will have to obtain any additional funding we need through debt and equity markets or the sale of producing or non-producing assets. There is no assurance that we will be able to obtain additional funding when it is required or that it will be available to us on commercially acceptable terms.

Low hydrocarbon price environments and the volatility in prices that we are currently experiencing, as well as operating difficulties and other factors, many of which are beyond our control, are causing our revenues and cash flows from operating activities to decrease and may limit our ability to internally fund our exploration and development activities.

We may make offers to acquire crude oil and natural gas properties in the ordinary course of our business. If these offers are accepted, our capital needs will increase substantially. If we fail to obtain the funding that we need when it is required, we may have to forego or delay potentially valuable opportunities to acquire new crude oil and natural gas properties. In addition, without the necessary funding, we may default on existing funding commitments to third parties and forfeit or dilute our rights in existing crude oil and natural gas property interests.

The crude oil and natural gas business is highly competitive, placing us at an operating disadvantage.

We expect to be at a competitive disadvantage in (a) seeking to acquire suitable crude oil and or natural gas drilling prospects; (b) undertaking exploration and development; and (c) seeking additional financing. We base our preliminary decisions regarding the acquisition of crude oil and or natural gas prospects and undertaking of drilling ventures upon general and inferred geology and economic assumptions. This public information is also available to our competitors.
In addition, we compete with larger crude oil and natural gas companies with longer operating histories and greater financial resources than us. These larger competitors, by reason of their size and greater financial strength, can more easily:

- access capital markets;

- recruit more qualified personnel;
- absorb the burden of any changes in laws and regulation in applicable jurisdictions;
- handle longer periods of reduced prices of crude oil and natural gas;
- acquire and evaluate larger volumes of critical information; and
- compete for industry-offered business ventures.

Our ability to reach and maintain profitable operating results is dependent on our ability to find, acquire, and develop crude oil and natural gas properties.

Our future performance depends upon our ability to find, acquire, and develop crude oil and natural gas reserves that are economically recoverable. Without successful exploration and acquisition activities, we will not be able to develop reserves or generate production revenues to achieve and maintain profitable operating results. No assurance can be given that we will be able to find, acquire or develop these reserves on acceptable terms. We also cannot assure that commercial quantities of crude oil and natural gas deposits will be discovered that are sufficient to enable us to recover our exploration and development costs.

Our limited capital expenditures and drilling program, when coupled with a sustained depression in crude oil and natural gas prices, will significantly reduce our cash flow and constrain any future drilling, which would have a material adverse effect on our business, financial condition and results of operations.

Historically, we have made substantial capital expenditures for the exploration and development of crude oil and natural gas reserves. The combination of lower hydrocarbon prices and the reduction of our drilling operations has resulted in reduced production and operating cash flows since June of 2014. A continued sustained volatility in these hydrocarbon prices combined with reduced production and accompanying lower cash flows will continue to adversely affect our business financial condition and results of operations.

Our proved reserves are estimates and depend on many assumptions. Any material inaccuracies in these assumptions could cause the quantity and value of our crude oil reserves, and our revenues, profitability and cash flows to be materially different from our estimates.

The accuracy of estimated proved reserves and estimated future net cash flows from such reserves is a function of the quality of available geological, geophysical, engineering and economic data and is subject to various assumptions, including assumptions required by the SEC relating to crude oil prices, drilling and operating expenses and other matters. Although we believe that our estimated proved reserves represent reserves that we are reasonably certain to recover, actual future production, crude oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil reserves will most likely vary from the assumptions and estimates used to determine proved reserves. Any significant variance could materially affect the estimated quantities and value of our crude oil reserves, which in turn could adversely affect our cash flows, results of operations, financial condition and the availability of capital resources. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil prices and other factors, many of which are beyond our control. Downward adjustments to our estimated proved reserves could require us to impair the carrying value of our crude oil properties, which would reduce our earnings and increase our stockholders' deficit.

The present value of proved reserves will not necessarily equal the current fair market value of our estimated crude oil reserves. In accordance with reserve reporting requirements of the SEC, we are required to establish economic production for reserves on an average historical price. Actual future prices and costs may be materially higher or lower than those required by the SEC. The timing of both the production and expenses with respect to the development and production of crude oil properties will affect the timing of future net cash flows from proved reserves and their present value.

The estimated proved reserve information is based upon reserve reports prepared by an independent engineer. From time to time, estimates of our reserves are also made by our company engineer for use in developing business plans and making various decisions. Such estimates may vary significantly from those of the independent engineers and may have a material effect upon our business decisions and available capital resources.

We may not be able to replace current production with new crude oil and natural gas reserves.

In general, the volume of production from a crude oil and natural gas property declines as reserves related to that property are depleted. The decline rates depend upon reservoir characteristics. In past years other than our East Slopes project in California, our crude oil and natural gas properties have had steep rates of decline and relatively short estimated productive lives.

Our identified drilling locations are scheduled out over multiple years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including hydrocarbon prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory and zoning approvals and other factors.

Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our business and results of operations.

Due to the volatility in crude oil prices and the lack of available drilling capital, we have not drilled any prospective development locations in California since November of 2013.

We may reclassify proved undeveloped reserves to unproved reserves due to our inability to commit sufficient capital within the required five-year development window, which could adversely affect the value of our properties.

The SEC generally requires that any undrilled location can be classified as a proved undeveloped reserve only if a development plan has been adopted indicating that the location is scheduled to be drilled within five years. The reduction of our drilling program in response to depressed crude oil and natural gas prices and a lack of drilling capital has impacted our ability to develop proved undeveloped reserves within such five-year period. If our reduced drilling plans continue over a significant period of time our future access to capital resources will be limited, and we will also likely further delay the development of our proved undeveloped reserves or ultimately suspend such development which could result in the reclassification of a significant amount of our proved undeveloped reserves as probable or possible reserves. A significant reclassification of proved undeveloped reserves could adversely affect the value of our properties.

Our producing reserves are located in one major geographic area. Concentration of reserves in limited geographic areas may disproportionately expose us to operational, regulatory and geological risks.

Our one core producing property is located in Kern County, California. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, or interruption of the processing or transportation of crude oil.

When we make the determination to invest in crude oil or natural gas properties we rely upon geological and engineering estimates, which involve a high level of uncertainty.

Geologic and engineering data are used to determine the probability that a reservoir of crude oil or natural gas exists at a particular location. This data is also used to determine whether crude oil and natural gas are recoverable from a reservoir. Recoverability is ultimately subject to the accuracy of data including, but not limited to, geological characteristics of the reservoir, structure, reservoir fluid properties, the size and boundaries of the drainage area, reservoir pressure, and the anticipated rate of pressure depletion. Also, an increase in the costs of production operations may render some deposits uneconomic to extract.

The evaluation of these and other factors is based upon available seismic data, computer modeling, well tests and information obtained from production of crude oil and natural gas from adjacent or similar properties. There is a high degree of risk in proving the existence and recoverability of reserves. Actual recoveries of proved reserves can differ materially from original estimates. Accordingly, reserve estimates may be subject to downward adjustment. Actual production, revenue and expenditures will likely vary from estimates, and such variances may be material.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations in the crude oil and natural gas industry can fluctuate significantly, often in correlation with crude oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher crude oil and natural gas prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews, and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be.

Drilling is a high risk activity and, as a result, we may not be able to adhere to our proposed drilling schedule, or our drilling program may not result in commercially productive reserves.

Our future success will partly depend on the success of our drilling programs. The future cost or timing of drilling, completing, and producing wells is inherently uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors including:

- unexpected drilling conditions;
- well integrity issues and surface expressions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- compliance with landowner requirements;
- current crude oil and natural gas prices and estimates of future crude oil and natural gas prices;
- availability, costs and terms of contractual arrangements with respect to pipelines and related facilities to gather, process, transport and market crude oil and natural gas; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

Our financial condition will deteriorate if we are unable to retain our interests in our leased crude oil and natural gas properties.

All of our properties are held under interests in crude oil and natural gas mineral leases. If we fail to meet the specific requirements of any lease, such lease may be terminated or otherwise expire. We cannot be assured that we will be able to meet our obligations under each lease. The termination or expiration of our “working interests” (interests created by the execution of a crude oil or natural gas lease) relating to these leases would impair our financial condition and results of operations.

We will need significant additional funds to meet capital calls, drilling and other production costs in our effort to explore, produce, develop and sell the crude oil and natural gas produced by our leases. We may not be able to obtain any such additional funds on acceptable terms.

Title deficiencies could render our crude oil and natural gas leases worthless; thus damaging the financial condition of our business.

The existence of a material title deficiency can render a lease worthless, resulting in a large expense to our business. We rely upon the judgment of crude oil and natural gas lease brokers who perform the fieldwork and examine records in the appropriate governmental office before attempting to place a specific mineral interest under lease. This is a customary practice in the crude oil and natural gas industry.

We anticipate that we, or the person or company acting as operator on the properties that we lease, will examine title prior to any well being drilled. Even after taking these precautions, deficiencies in the marketability of the title to the leases may still arise. Such deficiencies may render some leases worthless, negatively impacting our financial condition.

If we as operator of our crude oil project fail to maintain adequate insurance, our business could be exposed to significant losses.

Our crude oil projects are subject to risks inherent in the crude oil and natural gas industry. These risks involve explosions, uncontrollable flows of crude oil, natural gas or well fluids, pollution, fires, earthquakes and other environmental issues. These risks could result in substantial losses due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage. As protection against these operating hazards we maintain insurance coverage to include physical damage and comprehensive general liability. However, we are not fully insured in all aspects of our business. The occurrence of a significant event on any project against which we are not adequately covered by insurance could have a material adverse effect on our financial position.

In any project in which we are not the operator, we will require the operator to maintain insurance of various types to cover our operations with policy limits and retention liability customary in the industry. The occurrence of a significant adverse event on any of these projects if they are not fully covered by insurance could result in the loss of all or part of our investment. The loss of any such project investment could have a material adverse effect on our financial condition and results of operations.

New technologies may cause our current exploration and drilling methods to become obsolete.

There have been rapid and significant advancements in technology in the natural gas and crude oil industry, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial increase in cost. Further, competitors may obtain patents which might prevent us from implementing new technologies. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

Risks related to Environmental Regulation

Recent and future actions by the state of California could result in restrictions to our operations and result in decreased demand for oil and gas within the state.

In September 2020, Governor Gavin Newsom of California issued an executive order (Order) that seeks to reduce both the demand for and supply of petroleum fuels in the state. The Order establishes several goals and directs several state agencies to take certain actions with respect to reducing emissions of GHGs, including, but not limited to: phasing out the sale of new emissions-producing passenger vehicles, drayage trucks and off-road vehicles by 2035 and, to the extent feasible, medium and heavy duty trucks by 2045; developing strategies for the closure and repurposing of oil and gas facilities in California; and proposing legislation to end the issuance of new hydraulic fracturing permits in the state by 2024. The Order also directs the California Department of Conservation, Geologic Energy Management Division (CalGEM) to strictly enforce bonding requirements for oil and gas operations and to complete its ongoing public health and safety review of oil production and propose additional regulations, which are expected to include expanded land use setbacks or buffer zones.

In October 2020, the Governor issued an executive order that establishes a state goal to conserve at least 30% of California's land and coastal waters by 2030 and directs state agencies to implement other measures to mitigate climate change and strengthen biodiversity. In February 2021, SB 467 was introduced in the state senate. If passed, the bill would ban new permits for hydraulic fracturing, acid well stimulation treatments, cyclic steaming, water flooding and steam flooding – beginning in 2022 and would ban these activities in total beginning in 2027. The bill would also allow local governments to prohibit such practices prior to 2027. After the bill was introduced one of the authors announced that it would also be amended to also add a 2,500 feet setback for new wells from sensitive receptors. We cannot predict the outcome of this most recent legislative effort. Previous high profile efforts to pass mandatory setbacks have failed; however, any of the foregoing developments and other future actions taken by the state may materially and adversely affect our operations and properties and the demand for our products.

We face various risks associated with the trend toward increased anti-crude oil and natural gas development activity.

In recent years, we have seen significant growth in opposition to crude oil and natural gas development in the United States. Companies in our industry can be the target of opposition to hydrocarbon development from stakeholder groups, including national, state and local governments, regulatory agencies, non-government organizations and public citizens. This opposition is focused on attempting to limit or stop hydrocarbon development. Examples of such opposition include: efforts to reduce access to public and private lands; delaying or canceling permits for drilling or pipeline construction; limiting ore banning industry techniques such as hydraulic fracturing, and/or adding restrictions on or the use of water and associated disposal; imposition of set-backs on crude oil and natural gas sites; delaying or denying air-quality permits; advocating for increased punitive taxation or citizen ballot initiatives or moratoriums on industry activity; and the use of social media channels to cause reputational harm. Recent efforts by the US Administration to modify federal crude oil and natural gas regulations could intensify the risk of anti-development efforts from grass roots opposition.

Our need to incur costs associated with responding to these anti-development efforts, including legal challenges, or complying with any new legal or regulatory requirements from these efforts, could have a material adverse effect on our business.

Restricted land access could reduce our ability to explore for and develop crude oil and natural gas reserves.

Our ability to adequately explore for and develop crude oil and natural gas resources is affected by a number of factors related to access to land. Examples of factors which reduce our access to land include, among others:

- new municipal, state or federal land use regulations, which may restrict drilling locations or certain activities such as hydraulic fracturing;
- local and municipal government control of land or zoning requirements, which can conflict with state law and deprive land owners of property development rights;
- landowner, community and/or governmental opposition to infrastructure development;
- regulation of federal and Indian land by the Bureau of Land Management;
- anti-development activities, which can reduce our access to leases through legal challenges or lawsuits, disruption of drilling, or damage to equipment;
- the presence of threatened or endangered species or of their habitat;
- Disputes regarding leases; and
- Disputes with landowners, royalty owners, or other operators over such matters as title transfer, joint interest billing arrangements, revenue distribution, or production or cost sharing arrangements.

Reduced ability to obtain new leases could constrain our future growth and opportunity resulting in a material adverse effect on our business, financial condition, results of operations and our cash flows.

Our crude oil and natural gas exploration and production, and related activities are subject to extensive environmental regulations, and to laws that can give rise to substantial liabilities from environmental contamination.

Our operations are subject to extensive federal, state and local environmental laws and regulations, which impose limitations on the discharge of pollutants into the environment, establish standards for the management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose obligations to investigate and remediate contamination in certain circumstances. Liabilities to investigate or remediate contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage, may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated, and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate. Such liabilities may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, such liabilities may also be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Environmental requirements generally have become more stringent in recent years, and compliance with those requirements more expensive.

We have incurred expenses in connection with environmental compliance, and we anticipate that we will continue to do so in the future. Failure to comply with extensive applicable environmental laws and regulations could result in significant civil or criminal penalties and remediation costs. Some of our properties may be affected by environmental contamination that may require investigation or remediation. In addition, claims are sometimes made or threatened against companies engaged in crude oil and natural gas exploration and production by owners of surface estates, adjoining properties or others alleging damage resulting from environmental contamination and other incidents of operation. Compliance with, and liabilities for remediation under, these laws and regulations, and liabilities concerning contamination or hazardous materials, may adversely affect our business, financial condition and results of operations.

Climate change legislation or regulations restricting emissions of greenhouse gases ("GHG") could result in increased operating costs and reduced demand for the crude oil we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration by states or groupings of states of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment and has adopted regulations under existing provisions of the Clean Air Act. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, onshore and offshore crude oil and natural gas production facilities and onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the crude oil and natural gas industry, including gathering and boosting facilities and blowdowns of natural gas transmission pipelines, and in January 2016, the EPA proposed additional revisions to leak detection methodology.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that require reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could cause us to incur increased costs that could have an adverse effect on our business, financial condition and results of operations. Moreover, such new legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for crude oil and natural gas, which could reduce the demand for the crude oil or natural gas we produce and lower the value of our reserves.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions can interfere with our production and increase our operating expenses. Such damage or increased expenses from extreme weather may not be fully insured. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Risks Related to Our Indebtedness

We have experienced significant operating losses in the past and there can be no assurance that we will become profitable in the future.

We have reported net loss of approximately $398,450 for the year ended February 28, 2022, and we have an accumulated deficit through February 28, 2022 of approximately $29.5 million. Without successful exploration and development of our properties and a significant sustained increase in hydrocarbon prices any investment in Daybreak could become devalued or worthless.

We have substantial indebtedness. The amount of our outstanding indebtedness and our current inability to meet our debt obligations will have adverse consequences on our business, financial condition and results of operations.

At February 28, 2022, we had approximately $4.3 million of consolidated indebtedness comprised of a variety of short-term and long-term borrowings; a line of credit; trade payables; and 12% Subordinated Notes. The 12% Notes had a maturity date of January 29, 2019 and the principal balance of $315,000 has not been paid. The level of indebtedness we have affects our operations in a number of ways. We will need to use a portion of our cash flow to meet principal, interest and payables commitments; which reduces the amount of funds we will have available to finance our operations. This lack of funds limits planning for or reacting to changes in our business and the industry in which we operate and could limit our ability to make funds available for other purposes, such as future exploration, development or acquisition activities. Our ability to meet our debt service obligations and reduce our total indebtedness will depend upon our future performance. Our future performance, in turn, is dependent upon many factors that are beyond our control such as the level of hydrocarbon prices and general economic, financial and business conditions. We cannot guarantee that our future performance will not be adversely affected by such economic conditions and financial, business and other factors.

General Risk Factors

Certain U.S. federal income tax deductions currently available with respect to crude oil and natural gas exploration and development may be eliminated as a result of proposed legislation.

Legislation previously has been proposed that would, if enacted into law, make significant changes to United States federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to crude oil and natural gas exploration and production companies. These changes include, but are not limited to: (1) the repeal of the percentage depletion allowance for crude oil and natural gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for certain U.S. domestic production activities, and (4) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this type of legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to crude oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our Common Stock as well as affect our financial condition and results of operations.

We may lose key management personnel which could endanger the future success of our crude oil and natural gas operations.

Our President and Chief Executive Officer, who is also acting as our interim principal finance and accounting officer, our Director of Field Operations, and two of our directors each have substantial experience in the crude oil and natural gas business. The loss of any of these individuals could adversely affect our business. If one or more members of our management team dies, becomes disabled or voluntarily terminates employment with us, there is no assurance that a suitable or comparable substitute will be found.

A terrorist attack, anti-terrorist efforts or other armed conflict could adversely affect our business by decreasing our revenues and increasing our costs.

A terrorist attack, anti-terrorist efforts or other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for crude oil and natural gas, potentially putting downward pressure on demand for our services and causing a decrease in our revenues. Crude oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of crude oil and natural gas production are destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Related to Our Common Stock

We may be unable to continue as a going concern in which case our securities will have little or no value.

Our financial statements for the year ended February 28, 2022 were prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. We have incurred net losses since inception, which raises substantial doubt about our ability to continue as a going concern. In the event we are not able to continue operations, an investor will likely suffer a complete loss of their investment in our securities.

The market price of our Common Stock has been volatile, which may cause the investment value of our stock to decline.

Daybreak's Common Stock (OTC Pink: DBRM) trades on the OTC Pink® Open Market under the OTC Markets Group segment, Pink Current Information. Prior to May 1, 2016, our stock had traded on the OTCQB Venture Marketplace. Our transition to the OTC Pink® Open Market was the result of a cost-savings move for the company related to listing fees on the Venture Marketplace.

Because of the limited liquidity of our stock, shareholders may be unable to sell their shares at or above the cost of their purchase prices. The trading price of our shares has experienced wide fluctuations and these shares may be subject to similar fluctuations in the future.

The trading price of our Common Stock may be affected by a number of factors including events described in these risk factors, as well as our operating results, financial condition, announcements of drilling activities, general conditions in the crude oil and natural gas exploration and development industry including volatility in crude oil and natural gas prices, and other events or factors. The instability and volatility in hydrocarbon prices that has occurred since June 2014, has had a corresponding material and mostly adverse impact on our revenues and a similar direct material adverse impact on the trading price of our Common Stock.

In recent years, broad stock market indices, in general, and smaller capitalization companies, in particular, have experienced substantial price fluctuations. In a volatile market, we do experience wide fluctuations in the market price of our Common Stock. These fluctuations may have a negative effect on the market price of our Common Stock.

Pursuant to SEC rules our Common Stock is classified as a "penny stock" increasing the risk of investment in these shares.

Our Common Stock is designated as a "penny stock" and thus may be more illiquid than shares traded on an exchange or on NASDAQ. Penny stocks generally are any non-NASDAQ or non-exchange listed equity securities with a price of less than $5.00, subject to certain exceptions.

The "penny stock" reporting and disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for a stock that is subject to these rules. The market liquidity for the shares could be severely and adversely affected by limiting the ability of broker-dealers to sell these shares.

We have a limited operating history on which to base an investment decision.

To date, while we generally have had positive cash flow from our operations in California, we have not yet generated sustainable positive cash flow or earnings on a company-wide basis. We cannot provide any assurances that we will ever operate profitably especially in the current low-priced hydrocarbon environment. As a result of our limited operating history, we are more susceptible to business risks. These risks include unforeseen capital requirements, failure to establish business relationships, and competitive disadvantages against larger and more established companies.

The resale of shares offered in private placements could depress the value of the shares.

In the past, shares of our Common Stock have been offered and sold in private placements at significant discounts to the trading price of the Common Stock at the time of the offering. Sales of substantial amounts of Common Stock eligible for future sale in the public market, or the availability of shares for sale, including shares issued upon exercise of outstanding warrants, could adversely affect the prevailing market price of our Common Stock and our ability to raise capital by an offering of equity securities.

Privately placed issuances of our Common Stock, Preferred Stock and warrants have and may continue to dilute ownership interests which could have an adverse effect on our stock prices.

Our authorized capital stock consists of 200,000,000 shares of Common Stock and 10,000,000 shares of preferred stock. As of February 28, 2022, there were 67,802,273 shares of Common Stock issued and outstanding.

Historically we have issued, and likely will continue to issue, additional shares of our Common Stock in connection with the compensation of personnel, future acquisitions, private placements, possible equity swaps for debt or for other business purposes. Future issuances of substantial amounts of these equity securities could have a material adverse effect on the market price of our Common Stock, and would result in further dilution of the ownership interests of our existing shareholders.

We will need to seek to raise additional funds in the future through debt financing, which may impose operational restrictions and may further dilute existing ownership interests.

We expect to seek to raise additional capital in the future to help fund our acquisition, development, and production of crude oil and natural gas reserves. In the past, we have obtained debt financing through commercial loans and credit facilities. Subsequent debt financing, if available, may require restrictive covenants, which may limit our operating flexibility. Future debt financing may also involve debt instruments that are convertible into or exercisable for Common Stock. The conversion of the debt to equity financing may dilute the equity position of our existing shareholders.

We do not anticipate paying dividends on our Common Stock, which could devalue the market value of these securities.

We have not paid any cash dividends on our Common Stock since the Company's inception in 1955. We do not anticipate paying cash dividends in the foreseeable future. Any dividends paid in the future will be at the complete discretion of our Board of Directors. For the foreseeable future, we anticipate that we will retain any revenues that we may generate from our operations. These retained revenues will be used to finance and develop the growth of the Company. Prospective investors should be aware that the absence of dividend payments could negatively affect the market value of our Common Stock. Investors must rely on sales of their Common Stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Investors seeking cash dividends should not purchase our Common Stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As a smaller reporting company, we are not required to provide the information otherwise required by this Item.

ITEM 2. PROPERTIES

We conduct all of our drilling, exploration and production activities in the United States. All of our crude oil assets are located in the United States, and all of our revenues are derived from sales to customers within the United States. During the year ended February 28, 2022, we were involved in the operation of a 20 well oilfield project in Kern County, California.

We have not filed any estimates of total, proved net crude oil or natural gas reserves with any federal agency other than this report to the SEC for the fiscal year ended February 28, 2022. Throughout this Annual Report on Form 10-K, crude oil is shown in barrels (“Bbls”); natural gas is shown in thousands of cubic feet (“Mcf”) or British Thermal Units (“BTU”) unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent (“BOE”).

Kern County, California (East Slopes Project)

The East Slopes Project is located in the southeastern part of the San Joaquin Basin near Bakersfield, California. Drilling targets are porous and permeable sandstone reservoirs that exist at depths of 1,200 feet to 4,500 feet. Since January 2009, we have participated in the drilling of 25 wells in this project. We have been the Operator at the East Slopes Project since March 2009.

Our 20 producing crude oil wells in the East Slopes Project produce from five reservoirs at our Sunday, Bear, Black, Ball and Dyer Creek locations. The Sunday property has six producing wells, while the Bear property has nine producing wells. The Black property is the smallest of all currently producing reservoirs, and currently has two producing wells at this property. The Ball property also has two producing wells while the Dyer Creek property has one producing well. Our average working interest and NRI in these 20 producing crude oil wells is 36.6% and 28.4%, respectively.

There are several other similar prospects on trend with the Bear, Black and Dyer Creek reservoirs exhibiting the same seismic characteristics. Some of these prospects, if successful, would utilize the Company’s existing production facilities. In addition to the current field development, there are several other exploratory prospects that have been identified from the seismic data, which we plan to drill in the future.

Sunday Central Processing and Storage Facility

The crude oil produced from our acreage in California is considered heavy crude oil. The crude oil ranges from 14° to 16° API gravity. All of the crude oil from our five producing properties is processed, stored and sold from the Sunday central processing and storage facility. The crude oil must be heated to separate and remove water to prepare it to be sold. We constructed these facilities during the summer and fall of 2009 and at the same time established electrical service for our field by constructing three miles of power lines. In 2013, we completed an upgrade to this facility including the addition of a second crude oil storage tank to handle the additional crude oil production from the wells drilled in 2013.

By utilizing the Sunday centralized production facility our average production expenses have been reduced from over $40 per barrel in 2009 to around $24 per barrel of crude oil for the year ended February 28, 2022. With this centralized facility and having permanent electrical power available, we are ensuring that our operating expenses are kept to a minimum.

California Producing Properties

Sunday Property

In November 2008, we made our initial crude oil discovery drilling the Sunday #1 well. The well was put on production in January 2009. Production is from the Vedder Sand at approximately 2,000 feet. During 2009, we drilled three development wells including one horizontal well: the Sunday #2, Sunday #3 and Sunday #4H wells, respectively. During May and June 2013, we drilled two additional development wells: the Sunday #5 and Sunday #6. We have a 37.5% working interest with a 26.1% net revenue interest (“NRI”) in the Sunday #1 well. For the Sunday #2 and Sunday #3 wells, we have a 33.8% working interest with a 24.3% NRI. In the Sunday #4H well, we have a 33.8% working interest with a 27.1% NRI. In both the Sunday #5 and Sunday #6 wells we have a 37.5% working interest and a NRI of 30.1%. Our average working interest and NRI for the Sunday property six producing wells in aggregate is 35.6% and 27.0%, respectively. The Sunday reservoir is estimated to be approximately 35 acres in size with the potential for at least five more development wells to be drilled in the future.

Bear Property

In February 2009, we made our second crude oil discovery drilling the Bear #1 well, which is approximately one mile northwest of our Sunday discovery. The well was put on production in May 2009. Production is from the Vedder Sand at approximately 2,200 feet. In December 2009, we began a development program on this property by drilling and completing the Bear #2 well. In April 2010, we successfully drilled and completed the Bear #3 and the Bear #4 wells. In May and June 2013, we drilled three additional development wells, the Bear #5, Bear #6 and Bear #7, on this property. In November 2013, we drilled and put on production two additional development wells: Bear #8 and Bear #9. We have a 37.5% working interest in all wells on the Bear property. Our NRI in the Bear #1, Bear #2, Bear #3 and Bear #4 wells is 26.1%. For the Bear #5, Bear #6 and Bear #7 wells our NRI is 30.1%. Our NRI in the Bear #8 and Bear #9 wells is 31.7%. The average working interest and NRI for the Bear property for the ten producing wells in aggregate is 37.5% and 28.7%, respectively. The Bear reservoir is estimated to be approximately 62 acres in size with the potential for at least eleven more development wells to be drilled in the future.

Black Property

The Black property was acquired through a farm-in arrangement with a local operator. The Black property is just south of the Bear property on the same fault system. The Black #1 well was completed and put on production in January 2010. Production is from the Vedder Sand at approximately 2,200 feet. In May 2013, we drilled a development well, the Black #2, on this property. We have a 33.8% working interest with a 26.8% NRI in the two producing wells on this property. The Black reservoir is estimated to be approximately 13 acres in size with the potential for at least three more development wells to be drilled in the future.

Ball Property

The Ball #1-11 well was put on production in late October 2010. In June 2013 we drilled a development well, the Ball #2-11, on this property. Production on this property is from the Vedder Sand at approximately 2,500 feet. We have a 37.5% working interest with a 31.7% NRI in the two producing wells on this property. Our 3-D seismic data indicates a reservoir of approximately 38 acres in size with the potential for at least three more development wells to be drilled in the future.

Dyer Creek Property

The Dyer Creek #67X-11 (“DC67X”) well was also put on production in late October 2010. This well produces from the Vedder Sand and is located to the north of the Bear property on the same trapping fault. We have a 37.5% working interest with a 31.7% NRI in all wells on this property. The Dyer Creek property has the potential for at least one development well in the future.

California Drilling Plans

We plan to drill four development wells in our East Slopes project area in the 2022 – 2023 fiscal year once additional financing is put in place. When new financing is secured, the capital investment required for the four development wells is $525,000.

Encumbrances

On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payables owed to the partner by the Company.

Reserves

Crude oil is shown in barrels (“Bbls”); natural gas is shown in thousands of cubic feet (“Mcf”) or British Thermal Units (“BTU”) unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent (“BOE”). The following table sets forth our estimated net quantities of proved reserves as of February 28, 2022.

As of February 28, 2022, our total reserves were comprised of our working interest in East Slopes Project located in Kern County, California.

	Proved Reserves			
Reserve Category	**Crude Oil (Barrels)**	**Natural Gas (Mcf)**	**Total Crude Oil Equivalents (BOE)**	**Percent of Oil Equivalents (BOE)**
Developed	117,844	—	117,844	22.8%
Undeveloped	399,311	—	399,311	77.2%
Total Proved	517,155	—	517,155	100.0%

Changes in our estimated total net proved reserves for the twelve months ended February 28, 2022 are set forth in the table below.

	Proved Reserves (BOE)
Balance as of February 28, 2021	434,223
Revisions	3,052
Discoveries and extensions	89,493
Production	(9,613)
Balance as of February 28, 2022	517,155

Revisions. Net upward revisions of 3,052 BOE in aggregate were due to higher crude oil prices in California during the twelve months ended February 28, 2022 increasing the economic life of our proved reserves.

Discoveries and extensions. For the twelve months ended February 28, 2022, net extensions of 89,493 BOE reserves were added in California due to an increase in economic PUD locations.

Production. Production in California was 9,613 BOE in aggregate of proved reserves for the twelve months ended February 28, 2022.

As of February 28, 2022, our total proved undeveloped reserves were comprised of our interests in Kern County, California.

Changes in our estimated net proved undeveloped reserves for the twelve months ended February 28, 2022 are set forth in the table below.

	Proved Undeveloped Reserves (BOE)
Balance as of February 28, 2021	339,103
Revisions	(29,285)
Discoveries and extensions	89,493
Balance as of February 28, 2022	399,311

Revisions. There were net downward revisions of 29,285 BOE in aggregate due to lower estimated reservoir production of our proved undeveloped reserves.

Discoveries and extensions. For the twelve months ended February 28, 2022, there were 89,493 BOE in extensions due to an increase in economic PUD locations in California.

Our estimated net proved developed producing reserves in California at February 28, 2022 are set forth in the table below.

	Proved Developed Reserves			
Location	**Oil (Barrels)**	**Natural Gas (Mcf)**	**Total Oil Equivalents (BOE)**	**Percent of Oil Equivalents (BOE)**
California	117,844	—	117,844	100.0%

Our estimated net proved undeveloped reserves in California at February 28, 2021 are set forth in the table below.

	Proved Undeveloped Reserves			
Location	Oil (Barrels)	Natural Gas (Mcf)	Total Oil Equivalents (BOE)	Percent of Oil Equivalents (BOE)
California	399,311	—	399,311	100.0%

The Company has 273,265 Bbls of proved undeveloped reserves that have remained undeveloped for a period greater than five years. These proved undeveloped reserves have remained undeveloped due to depressed crude oil and natural gas prices and a lack of capital available for drilling. Under our current drilling plans, we intend to convert all 273,265 BOE or 100.0% of the proved undeveloped reserves disclosed as of February 28, 2022 into proved developed reserves within the next five years.

Our estimated proved reserves (BOE) and PV-10 valuation in California at February 28, 2022 are set forth in the table below.

	Proved Reserves		
Location	Total Oil Equivalents (BOE)	PV-10 of Proved Reserves	PV-10 as a Percentage of Proved Reserves
California	517,155	6,191,944	100.0%

The present value of future net cash flows from proved reserves, before deductions for estimated future income taxes and asset retirement obligations, discounted at 10% (“PV-10”), was approximately $6.2 million at February 28, 2022 an increase of approximately $4.5 million or 287.5% from the PV-10 reserve valuation at February 28, 2021. This increase is due to the increase in the base price of crude oil in the current report in comparison to the base price of crude oil in the February 28, 2021 report; and an increase in both PDP and PUD reserve totals. . The commodity prices used to estimate proved reserves and their related PV-10 at February 28, 2022 were based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the twelve month period from March 2021 through February 2022. The WTI benchmark average price for the twelve months ended February 28, 2022 was $71.69 per barrel of crude oil in comparison to $38.64 in the prior year reserve report.

These benchmark average prices were further adjusted for crude oil quality and gravity, transportation fees and other price differentials resulting in an average realized price in California for the February 28, 2022 reserve report of $68.80 in comparison to $36.14 in the February 28, 2021 reserve report. Adverse changes in any price differential would reduce our cash flow from operations and the PV-10 of our proved reserves. Operating costs were not escalated.

PV-10 is not a generally accepted accounting principal (“GAAP”) financial measure, but we believe it is useful as a supplemental disclosure to the standardized measure of discounted future net cash flows presented in our financial statements. The PV-10 of proved reserves is based on prices and discount factors that are consistent for all companies and can be used within the industry and by securities analysts to evaluate proved reserves on a comparable basis.

Reserve Estimation

All of our estimated proved reserves of 517,155 BOE for the twelve months ended February 28, 2022 were derived from engineering reports prepared by PGH Petroleum and Environmental Engineers, LLC (“PGH”) of Austin, Texas in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC.

PGH is an independent petroleum engineering consulting firm registered in the State of Texas, and Frank J. Muser, a Petroleum Engineer, is the technical person at PGH primarily responsible for evaluating the proved reserves covered by their report. Mr. Muser graduated from the University of Texas at Austin with a Bachelor of Science degree in Chemical Engineering. He is a licensed Professional Engineer in the states of Texas, Alabama, Kansas, North Dakota and West Virginia and has been employed by PGH as a staff engineer since 2012. Mr. Muser has over 20 years of extensive crude oil and natural gas experience working in both private industry and for the State of Texas. The services provided by PGH are not audits of our reserves but instead consist of complete engineering evaluations of the respective properties. For more information about the evaluations performed by PGH, refer to the copy of their report filed as an exhibit to this Annual Report on Form 10-K.

Our internal controls over the reserve reporting process are designed to result in accurate and reliable estimates in compliance with applicable regulations and guidance. Internal reserve preparation is performed by Bobby Ray Greer, Director of Field Operations. Mr. Greer is a 1984 graduate of University of Southern Mississippi in Hattiesburg, Mississippi with a Bachelor of Science Degree in Geology and is a certified Petroleum Geologist and a member, in good standing, of the American Association of Petroleum Geologists and is a registered professional geologist in Mississippi. Mr. Greer has over 35 years of experience in petroleum exploration, reservoir analysis, drilling rig construction, oilfield operations and management.

Although we believe that the estimates of reserves prepared by Mr. Greer have been prepared in accordance with professional engineering standards consistent with SEC and FASB guidelines, we engage an independent petroleum engineering consultant to prepare an annual evaluation of our estimated proved reserves. We provide to PGH for their analysis all pertinent data needed to properly evaluate our reserves. We consult regularly with PGH during the reserve estimation process to review properties, assumptions, and any new data available. Additionally, the Company's senior management reviewed and approved all Daybreak reserve report information contained in this Annual Report on Form 10-K.

Under current SEC standards, proved reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of crude oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field-tested and have demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we employ technologies that have been demonstrated to yield results with consistency and repeatability. The technical data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Generally, crude oil and natural gas reserves are estimated using, as appropriate, one or more of these available methods: production decline curve analysis, analogy to similar reservoirs or volumetric calculations. Reserves attributable to producing wells with sufficient production history are estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and technical data to assess the reservoir continuity. In some instances, particularly in connection with exploratory discoveries, analogous performance data is not available, requiring us to rely primarily on volumetric calculations to determine reserve quantities. Volumetric calculations are primarily based on data derived from geologic-based seismic interpretation, open-hole logs and completion flow data. When using production decline curve analysis or analogy to estimate proved reserves, we limit our estimates to the quantities of crude oil derived through volumetric calculations.

The accuracy of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation and judgment. The estimates of reserves and future cash flows are based on various assumptions and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable crude oil reserves may vary substantially from these estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the crude oil and natural gas industry in general are subject.

Delivery Commitments

As of February 28, 2022, we had no commitments to provide any fixed or determinable quantities of crude oil or natural gas in the near future under contracts or agreements.

Summary Operating Data

The following table sets forth our net share of annual production in each project for the periods shown. One barrel of crude oil equivalent ("BOE") is roughly equivalent to 6,000 cubic feet or 6 Mcf of gas.

As of February 28, 2022, our total reserves were comprised of our working interest in East Slopes Project located in Kern County, California.

	For the Twelve Months Ended February 28/29,		
	2022	2021	2020
Crude Oil and Natural Gas Production Data:			
California crude oil	9,613	10,970	11,013
Total (BOE)	9,613	10,970	11,013

The following table sets forth our net share of crude oil and natural gas revenue by project area for the periods shown.

	For the Twelve Months Ended February 28/29,		
	2022	2021	2020
Crude Oil and Gas Revenue:			
California crude oil	680,107	404,901	663,512
Total	$ 680,107	$ 404,901	$ 663,512

The following table sets forth the average realized sales price from each project area for the periods shown.

	For the Twelve Months Ended February 28/29,		
	2022	2021	2020
Average Realized Price:			
Crude oil – California (Bbl)	$ 70.75	$ 36.91	$ 60.25

The following table sets forth the average production expense (BOE) for the periods shown.

	For the Twelve Months Ended February 28/29,		
	2022	2021	2020
Average Production Expense (BOE):			
California	$ 24.06	$ 17.12	$ 16.43

Gross and Net Acreage

The following table sets forth our interests in developed and undeveloped crude oil lease acreage in California held by us as of February 28, 2022. These ownership interests generally take the form of working interests in crude oil leases that have varying terms. Developed acreage includes leased acreage that is allocated or assignable to producing wells. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of crude oil, regardless of whether or not the acreage contains proved reserves. Gross acres represents the total number of acres in which we have an interest. Net acres represents the sum of our fractional working interests owned in the gross acres.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	800	292	2,694	1,010	3,494	1,302
Average working interest		36.5%		44.2%		42.7%

Undeveloped Acreage Expirations

The following table sets forth expiration dates of our gross and net undeveloped acres in California for the years shown.

	Twelve Months Ended February 28, 2022		Twelve Months Ended February 28, 2023		Twelve Months Ended February 29, 2024	
	Gross	Net	Gross	Net	Gross	Net
California	—	—	—	—	—	—
Average working interest		—		—		

In all cases the drilling of a commercial crude oil or natural gas well will hold acreage beyond the lease expiration date. In the past we have been able to, and expect in the future to be able to extend the lease terms of some of these leases. Based on our evaluation of prospective economics, we have allowed acreage to expire from time to time and we expect to allow additional acreage to expire in the future. In California, we have previously determined that there is no likely benefit to pursuing any drilling opportunities on the majority of the expiring leases, so the expiration of these leases is expected to be immaterial to our operations. Further, none of our proved undeveloped reserves have been assigned to locations that are scheduled to be drilled after the expiration of the current leases. In California, all of our proved undeveloped reserves are assigned to leases that are currently held by production ("HBP").

Producing Wells

The following table sets forth our gross and net productive crude oil wells in California as of February 28, 2022. Productive wells are producing wells and wells capable of production. Gross wells represent the total number of wells in which we have an interest. Net wells represent the sum of our fractional working interests owned in the gross wells.

Property Location	Gross	Net
California	20	7.3
Average working interest		36.5%

Drilling Activity

The following table sets forth our exploratory and development well drilling activity in California for the periods shown. We have had no drilling activity in the past three years due to the volatility of crude oil prices and the lack of available drilling capital.

	Twelve Months Ended February 28, 2022		Twelve Months Ended February 28, 2021		Twelve Months Ended February 29, 2020	
Property Location	Productive	Dry	Productive	Dry	Productive	Dry
California						
Exploratory	—	—	—	—	—	—
Developmental	—	—	—	—	—	—
Total	—	—	—	—	—	—

ITEM 3. LEGAL PROCEEDINGS

Neither the Company, nor any of our officers or directors is a party to any material legal proceeding or litigation, and such persons know of no material legal proceeding or contemplated or threatened litigation. There are no judgments against us or our officers or directors. None of our officers or directors has been convicted of a felony or misdemeanor relating to securities or performance in corporate office.

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

Our Common Stock is quoted on the OTC Pink Open Market under the symbol "DBRM". Prior to May 1, 2016, our stock had traded on the OTCQB Venture Marketplace. Our transition to the OTC Pink Open Market resulted from a cost-savings program for the company and related to listing fees on the Venture Marketplace.

The following table sets forth the high and low closing sales prices for our Common Stock for the two most recent twelve month periods shown. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not represent actual transactions. The information is derived from information received from online stock quotation services.

	Twelve Months Ended February 28, 2022		Twelve Months Ended February 28, 2021	
	High	Low	High	Low
First Quarter	0.0670	0.0200	0.013	0.006
Second Quarter	0.0379	0.0220	0.012	0.007
Third Quarter	0.0530	0.0230	0.015	0.006
Fourth Quarter	0.0683	0.0225	0.029	0.006

As of June 14, 2022, the Company had 1,703 shareholders of record of its Common Stock. This number does not include an indeterminate number of shareholders whose shares are held by brokers in street name.

Transfer Agent

Effective December 22, 2020, the Company appointed Sedona Equity Registrar & Transfer, Incorporated ("Sedona") as its transfer agent and shareholder support provider. By December 28, 2020, all of the Company's directly held shares of common stock, files and information has been transferred from Computershare to Sedona. In this capacity, Sedona will manage all stock registry requests for shareholders, including change of address, certificate replacement and transfer of shares. All stock and investment information will automatically transfer to Sedona from our former Transfer Agent and Registrar, Computershare, and no action is required on the part of the shareholder.

The transfer agent for our Common Stock is Sedona Equity Registrar & Transfer, 143 W. Helena Drive Phoenix, AZ 85023. Their website address is: www.sedonaequity.com.

Dividend Policy

The Company has not declared or paid cash dividends or made any distributions on its common stock since its inception in 1955.
During the twelve months ended February 28, 2022, the Company paid the shareholders of its Series A Convertible Preferred stock all accrued and accumulated dividends that were associated with the Series A Convertible Preferred stock with common stock. For more information on this issuance please refer to Note 12 of the financial statements that are included in this 10-K filing. The Company does not anticipate that it will pay cash dividends or make any cash distributions on its common stock in the foreseeable future.

Preferred Stock

The Company is authorized to issue up to 10,000,000 shares of Preferred Stock with a par value of $0.001. Our Preferred Stock may be entitled to preference over the Common Stock with respect to the distribution of assets of the Company in the event of liquidation, dissolution, or winding-up of the Company, whether voluntarily or involuntarily, or in the event of any other distribution of assets of the Company among its shareholders for the purpose of winding-up its affairs. The authorized but unissued shares of Preferred Stock may be divided into and issued in designated series from time to time by one or more resolutions adopted by the Board of Directors. The directors in their sole discretion shall have the power to determine the relative powers, preferences, and rights of each series of Preferred Stock.

With the filing of our Second Amended and Restated Articles of Incorporation with the Washington Secretary of State in May 2022, the Company no longer has any preferred stock shares. We only have one class of stock and that is common stock.

Series A Convertible Preferred Stock

The Company designated 2,400,000 shares of the 10,000,000 preferred shares as Series A Convertible Preferred Stock ("Series A Preferred"), with a $0.001 par value. In July 2006, we completed a private placement of the Series A Preferred that resulted in the issuance of 1,399,765 Series A Preferred shares to 100 accredited investors.

During the twelve months ended February 28, 2022, the Company proposed to all 56 remaining Series A shareholders, who had not previously converted to the Company's common stock, the conversion of their Series A shares into three shares of the Company's common stock. Included with this proposal, the Company offered to pay any accrued Series A dividend, on a pro rata basis, with 1,100,000 shares of common stock. In order for the conversion to occur and the dividend to be paid, a majority of the Series A shares had to vote to accept the conversion proposal. With a majority of 53.6%, the outstanding shares voted in favor of the mandatory conversion and dividend issuance. There were 46.4% of the outstanding shares who chose to vote no; not to vote or had their notices of the conversion vote returned to the Company as an invalid address. As a result of the affirmative vote, 709,568 shares of Series A Preferred stock was converted to 2,128,704 shares of common stock and 1,100,000 shares of common stock were issued to satisfy the accumulated dividend of $2,449,979. At February 28, 2022, there were no outstanding shares of Series A Preferred stock remaining.

The following is a summary of the rights and preferences of the Series A Preferred.

Conversion:

At February 28, 2022, there were no shares issued and outstanding that had not been converted into our Common Stock. As of February 28, 2021, there were 44 accredited investors who had converted 690,197 Series A Preferred shares into 2,070,591 shares of Daybreak Common Stock.

The conversions of Series A Preferred that have occurred since the Series A Preferred was first issued in July 2006 are set forth in the table below.

Fiscal Period	Shares of Series A Preferred Converted to Common Stock	Shares of Common Stock Issued from Conversion	Number of Accredited Investors
Year Ended February 29, 2008	102,300	306,900	10
Year Ended February 28, 2009	237,000	711,000	12
Year Ended February 28, 2010	51,900	155,700	4
Year Ended February 28, 2011	102,000	306,000	4
Year Ended February 29, 2012	—	—	—
Year Ended February 28, 2013	18,000	54,000	2
Year Ended February 28, 2014	151,000	453,000	9
Year Ended February 28, 2015	3,000	9,000	1
Year Ended February 29, 2016	10,000	30,000	1
Year Ended February 28, 2017	—	—	—
Year Ended February 28, 2018	14,997	44,991	1
Year Ended February 28, 2019	—	—	—
Year Ended February 29, 2020	—	—	—
Year Ended February 28, 2021	—	—	—
Year Ended February 28, 2022	709,568	2,128,704	56
Totals	1,399,765	4,199,295	100

Dividends:

Holders of Series A Preferred shall be paid dividends, in the amount of 6% of the original purchase price per annum. Dividends may be paid in cash or Common Stock at the discretion of the Company. Dividends are cumulative from the date of the final closing of the private placement, whether or not in any dividend period or periods we have assets legally available for the payment of such dividends. Accumulations of dividends on shares of Series A Preferred do not bear interest. Dividends are payable upon declaration by the Board of Directors. During the twelve months ended February 28, 2022, all accumulated dividends of $2,449,979 were paid through the issuance of 1,100,000 shares of common stock.

Cumulative dividends earned for each twelve month period since issuance are set forth in the table below:

Fiscal Year Ended	Shareholders at Period End		Accumulated Dividends
February 28, 2007	100	$	155,311
February 29, 2008	90		242,126
February 28, 2009	78		209,973
February 28, 2010	74		189,973
February 28, 2011	70		173,707
February 29, 2012	70		163,624
February 28, 2013	68		161,906
February 28, 2014	59		151,323
February 28, 2015	58		132,634
February 29, 2016	57		130,925
February 28, 2017	57		130,415
February 28, 2018	56		128,231
February 28, 2019	56		127,714
February 29, 2020	56		128,063
February 28, 2021	56		127,714
February 28, 2022	—		96,340
		$	2,449,979

At a special meeting of shareholders on May 20, 2022 the Company's shareholders approved the Second Amended and Restated Articles of Incorporation, which eliminates the classification of the Series A Preferred.

Common Stock

The Company is authorized to issue up to 200,000,000 shares of $0.001 par value Common Stock of which 67,802,273 and 60,491,122 shares were issued and outstanding as of February 28, 2022 and February 28, 2021, respectively.

	Common Stock Balance		Par Value
Common stock, Issued and Outstanding, February 28, 2019	51,532,364		
Share issuances during the twelve months ended February 29, 2020	2,000,000	$	2,000
Common stock, Issued and Outstanding, February 29, 2020	53,532,364		
Share issuances during the twelve months ended February 28, 2021	6,958,758	$	6,959
Common stock, Issued and Outstanding, February 28, 2021	60,491,122		
Shares issued for Series A Preferred conversion	2,128,704	$	2,129
Shares issued for Series A accumulated dividend	1,100,000	$	1,100
Shares issued for debt conversion of accrued salaries	1,397,880	$	1,398
Shares issued for debt conversion of accrued directors fees	317,708	$	318
Shares issued for conversion of 12% Note principal and interest – related party	1,144,415	$	1,144
Shares issued for investment principal in production revenue program	1,222,444	$	1,222
Common stock, Issued and Outstanding, February 28, 2022	67,802,273		

During the twelve months ended February 28, 2022, there were 7,311,151 shares of common stock issued as a part of the Company's restructuring of its balance sheet in accordance with the conditions of the Equity Exchange Agreement between Reabold California, LLC, Gaelic Resources Ltd, and the Company. Of the total 7,311,151 shares issues, there were 4,082,447 shares issued to satisfy related party debt. Another 3,228,704 shares were issued to satisfy the Series A Preferred stock conversion and associated accumulated dividend. During the twelve months ended February 28, 2021, there were 6,958,758 shares of common stock shares valued at $27,835 issued to a related party to settle a convertible note payable.

All shares of Common Stock are equal to each other with respect to voting, liquidation, dividend and other rights. Owners of shares of Common Stock are entitled to one vote for each share of Common Stock owned at any shareholders' meeting. Holders of shares of Common Stock are entitled to receive such dividends as may be declared by the Board of Directors out of funds legally available therefore; and upon liquidation, are entitled to participate pro rata in a distribution of assets available for such a distribution to shareholders.

There are no conversion, preemptive, or other subscription rights or privileges with respect to any shares of our Common Stock. Our stock does not have cumulative voting rights, which means that the holders of more than 50% of the shares voting in an election of directors may elect all of the directors if they choose to do so. In such event, the holders of the remaining shares aggregating less than 50% would not be able to elect any directors.

Warrants

During the twelve months ended February 29, 2020 there were 2.1 million warrants issued to a third party for investor relations services. The fair value of the warrants was determined by the Black-Scholes pricing model, was $17,689, and is being amortized over the three year vesting period of the warrants. The Black-Scholes valuation encompassed the following assumptions: a risk-free interest rate of 1.68%; volatility rate of 260.23%; and a dividend yield of 0.0%.

The warrant contains a vesting blocking provision that prevents the vesting of any warrants that such vesting would cause the warrant holder's beneficial ownership (as such term is defined in Section 13d-3 of the Securities Exchange Act of 1934, as amended) to exceed more than four and ninety-nine one-hundredths percent (4.99%) of the Company's outstanding Common Stock. The foregoing restriction may not be waived by either party. The warrants vest in equal parts over a three year period beginning on January 2, 2020 and all warrants expire on January 2, 2024.

As of February 28, 2022 and February 28, 2021, there were 893,333 and 528,507 exercisable warrants. At February 28, 2022, both the outstanding warrants and the exercisable warrants had a weighted average exercise price of $0.01; a weighted average remaining life of 1.84 years, and an intrinsic value of $20,265. The recorded amount of warrant expense for the twelve months ended February 28, 2021 and February 28, 2021 was $4,913 and $5,897, respectively.

Warrant activity for the twelve months ended February 28, 2022 and February 28, 2021 is set forth in the table below:

	Warrants	Weighted Average Exercise Price
Warrants outstanding, February 29, 2020	2,100,000	$ 0.01
Changes during the twelve months ended February 28,2021:		
Issued	—	
Expired / Cancelled / Forfeited	—	
Warrants outstanding, February 28. 2021	2,100,000	$ 0.01
Warrants exercisable, February 28, 2021	528,507	
Changes during the twelve months ended February 28, 2022:		
Issued	—	$
Expired / Cancelled / Forfeited	—	
Warrants outstanding, February 28, 2022	2,100,000	$ 0.01
Warrants exercisable, February 28, 2022	893,333	$ 0.01

ITEM 6. RESERVED

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

The following management's discussion and analysis ("MD&A") is management's assessment of the financial condition, changes in our financial condition and our results of operations and cash flows for the twelve months ended February 28, 2022 and February 28, 2021. This MD&A should be read in conjunction with the audited financial statements and the related notes and other information included elsewhere in this Annual Report on Form 10-K.

Safe Harbor Provision

Certain statements contained in our Management's Discussion and Analysis of Financial Condition and Results of Operations are intended to be covered by the safe harbor provided for under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. All statements other than statements of historical facts contained in this MD&A report, including statements regarding our current expectations and projections about future results, intentions, plans and beliefs, business strategy, performance, prospects and opportunities, are inherently uncertain and are forward-looking statements. For more information about forward-looking statements, please refer to the section labeled "Cautionary Statement About Forward-Looking Statements" at the beginning of this Annual Report on Form 10-K.

Introduction and Overview

We are an independent crude oil and natural gas exploration, development and production company. Our basic business model is to increase shareholder value by finding and developing crude oil and natural gas reserves through exploration and development activities, and selling the production from those reserves at a profit. To be successful, we must, over time, be able to find crude oil and natural gas reserves and then sell the resulting production at a price that is sufficient to cover our finding costs, operating expenses, administrative costs and interest expense, plus offer us a return on our capital investment. A secondary means of generating returns can include the sale of either producing or non-producing lease properties.

Our long-term success depends on, among many other factors, the successful acquisition and drilling of commercial grade crude oil and natural gas properties as well as the prevailing sales prices for crude oil and natural gas along with associated operating expenses. The volatile nature of the energy markets makes it difficult to estimate future prices of crude oil and natural gas; however, any prolonged period of depressed prices, such as we are now experiencing, will have a material adverse effect on our results of operations and financial condition.

Our operations are focused on identifying and evaluating prospective crude oil and natural gas properties and funding projects that we believe have the potential to produce crude oil or natural gas in commercial quantities. We conduct all of our drilling, exploration and production activities in the United States, and all of our revenues are derived from sales to customers within the United States. We are currently in the process of developing a multi-well oilfield projects in Kern County, California and an exploratory project in Michigan.

Our management cannot provide any assurances that Daybreak will ever operate profitably. While we have experienced positive cash flow in the past from our crude oil operations in California, we have not yet generated sustainable positive cash flow or earnings on a company-wide basis. As a small company, we are more susceptible to the numerous business, investment and industry risks that have been more fully described in Item 1A. Risk Factors of this Annual Report on Form 10-K for the fiscal year ended February 28, 2022.

Throughout this Annual Report on Form 10-K, crude oil is shown in barrels ("Bbls"); natural gas is shown in thousands of cubic feet ("Mcf") or British Thermal Units ("BTU") unless otherwise specified, and hydrocarbon totals are expressed in barrels of oil equivalent ("BOE").

Year-to-Date Results

Below is brief summary of our crude oil and natural gas project in California. Refer to our discussion in Item 2. Properties, in this Annual Report on Form 10-K for more information on our East Slopes Project in Kern County, California.

Kern County, California (East Slopes Project)

The East Slopes Project is located in the southeastern part of the San Joaquin Basin near Bakersfield, California. Drilling targets are porous and permeable sandstone reservoirs that exist at depths of 1,200 feet to 4,500 feet. Since January 2009, we have participated in the drilling of 25 wells in this project. The crude oil produced from our acreage in the Vedder Sand is considered heavy crude oil. The produced crude oil ranges from 14° to 16° API gravity and must be heated to separate and remove water prior to sale. During the twelve months ended February 28, 2022 we had production from 20 vertical crude oil wells. Our average working interest and NRI in these 20 wells is 36.6% and 28.4%, respectively. We have been the Operator at the East Slopes Project since March 2009.

Results of Operations – For the years ended February 28, 2022 and February 28, 2021

California Crude Oil Prices

The price we receive for crude oil sales in California is based on prices posted for Midway-Sunset crude oil delivery contracts, contracts, less deductions that vary by grade of crude oil sold and transportation costs. The posted Midway-Sunset price generally moves in correlation to, and at a discount to, prices quoted on the New York Mercantile Exchange ("NYMEX") for spot West Texas Intermediate ("WTI") Cushing, Oklahoma delivery contracts. We do not have any natural gas revenues in California.

There continues to be a significant amount of volatility in hydrocarbon prices and a corresponding fluctuation in our realized sale price of crude oil does exist. An example of this volatility is that in June of 2014 the monthly average price of WTI oil was $105.79 per barrel and our realized price per barrel of crude oil was $98.78 while in April 2020, the monthly average price of WTI crude oil was $16.55 and our monthly realized price was $16.96 per barrel. Finally, in February 2022, the monthly average price of WTI oil was $91.64 per barrel and our realized price per barrel of crude oil was $87.41. This volatility in crude oil prices has continued throughout most of the fiscal year ended February 28, 2022. Any downward volatility in the price of crude oil will have a prolonged and substantial negative impact on our profitability and cash flow from our producing California properties. It is beyond our ability to accurately predict crude oil prices over any substantial length of time.

A comparison of the average WTI price and average realized crude oil sales price at our East Slopes Project in California for the twelve months ended February 28, 2022 and February 28, 2021 is shown in the table below:

	Twelve Months Ended		
	February 28, 2022	February 28, 2021	Percentage Change
Average twelve month WTI crude oil price	$ 73.31	$ 39.48	85.7%
Average twelve month realized crude oil sales price (Bbl)	$ 70.75	$ 36.91	91.7%

For the twelve months ended February 28, 2022, the average WTI price was $73.31 and our average realized crude oil sale price was $70.75, representing a discount of $2.56 per barrel or 3.5% lower than the average WTI price. In comparison, for the twelve months ended February 28, 2021, the average WTI price was $39.48 and our average realized sale price was $36.91 representing a discount of $2.57 per barrel or 6.5% lower than the average WTI price. Historically, the sale price we receive for California heavy crude oil has been less than the quoted NYMEX WTI price because of the lower API gravity of our California crude oil in comparison to WTI crude oil API gravity.

California Crude Oil Revenue and Production

Crude oil revenue in California for the twelve months ended February 28, 2022 increased $275,206 or 68.0% to $680,107 in comparison to revenue of $404,901 for the twelve months ended February 28, 2021. The average sale price of a barrel of crude oil for the twelve months ended February 28, 2022 was $70.75 in comparison to $36.91 for the twelve months ended February 28, 2021. The increase of $33.84 or 91.7% per barrel in the average realized price of a barrel of crude oil accounted for 134.9% of the increase in crude oil revenue for the twelve months ended February 28, 2022.

Our net sales volume for the twelve months ended February 28, 2022 was 9,613 barrels of crude oil in comparison to 10,970 barrels sold for the twelve months ended February 28, 2021. This decrease in crude oil sales volume of 1,357 barrels or 12.4% was primarily due to fewer well days of production and the natural decline in reservoir pressure during the twelve months ended February 28, 2021.

The gravity of our produced crude oil in California ranges between 14° API and 16° API. Production for the twelve months ended February 28, 2022 was from 20 wells resulting in 7,154 well days of production in comparison to 7,288 well days of production from 20 wells for the twelve months ended February 28, 2021.

Our crude oil sales revenue from California is set forth in the table below:

Project	Twelve Months Ended February 28, 2022		Twelve Months Ended February 28, 2021	
	Revenue	Percentage	Revenue	Percentage
Total crude oil revenues*	$ 680,107	100.0%	$ 404,901	100.0%

*Our average realized sale price on a BOE basis for the twelve months ended February 28, 2021 was $70.75 in comparison to $36.91 for the twelve months ended February 28, 2021, representing an increase of $33.84 or 91.7% per barrel.

Of the $275,206 or 68.0% increase in revenue for twelve months ended February 28, 2022 approximately $371,212 or 134.9% can be attributed to the increase in the realized price of crude oil.

Operating Expenses

Total operating expenses increased $187,178 or 24.8% to $940,886 for the twelve months ended February 28, 2022 in comparison to $753,708 for the twelve months ended February 28, 2021. Our operating expenses are set forth in the table below:

	Twelve Months Ended February 28, 2022			Twelve Months Ended February 28, 2021		
	Expenses	Percentage	BOE Basis	Expenses	Percentage	BOE Basis
Production expenses	$ 231,275	24.6%		$ 187,858	24.9%	
Exploration and drilling expenses	56,213	6.0%		83	0.0%	
Depreciation, Depletion, Amortization (“DD&A”)	49,590	5.3%		60,063	8.0%	
General and Administrative (“G&A”) expenses	603,808	64.1%		505,704	67.1%	
Total operating expenses	$ 940,886	100.0%	$ 97.88	$ 753,708	100.0%	$ 68.71

Production expenses include expenses associated with the production of crude oil and natural gas. These expenses include pumper salaries, electricity, road maintenance, control of well insurance, property taxes and well maintenance and workover expenses; and, relate directly to the number of wells that are on production. For the twelve months ended February 28, 2022, these expenses increased $43,417, or 23.1% to $231,276 in comparison to $187,858 for the twelve months ended February 28, 2021. We had 20 wells on production in California for the twelve months ended February 28, 2022 and February 28, 2021. Production expenses on a BOE basis in California for the twelve months ended February 28, 2022 and February 28, 2021 were $24.06 and $17.12, respectively. Production expenses represented 24.6% and 24.9% of total operating expenses for the twelve months ended February 28, 2022 and February 28, 2021, respectively.

Exploration and drilling expenses include geological and geophysical (“G&G”) expenses as well as leasehold maintenance, plugging and abandonment (“P&A”) expenses and dry hole expenses. These expenses increased $56,130 to $56,213 for the twelve months ended February 28, 2022 in comparison to $83 for the twelve months ended February 28, 2021. The increase was primarily due to the write off of exploration expenses related to the Michigan prospect. Exploration and drilling expenses represented 6.0% and 0.0% of total operating expenses for the twelve months ended February 28, 2022 and February 28, 2021, respectively.

Depreciation, Depletion, Amortization (“DD&A”) expense relates to equipment, proven reserves and property costs, and is another component of operating expenses. These expenses decreased $10,473 or 17.4% to $49,590 for the twelve months ended February 28, 2022 in comparison to $60,063 for the twelve months ended February 28, 2021. The primary reason for the decrease in DD&A expense was due to higher realized crude oil prices thus increasing the estimated economic life of our reserves in comparison to our reserve report from the prior year. On a BOE basis, DD&A expense in California for the twelve months ended February 28, 2022 and February 28, 2021 was $5.16 and $5.48, respectively. DD&A expenses represented 5.3% and 8.0% of total operating expenses for the twelve months ended February 28, 2022 and February 28, 2021, respectively.

General and administrative (“G&A”) expenses increased $98,104 or 19.4% to $603,808 for the twelve months ended February 28, 2022 in comparison to $505,704 for the twelve months ended February 28, 2021. The increase in G&A expenses was primary due to employees returning to work after temporary lay-offs due to the COVID-19 epidemic and increases in travel, insurance rates, legal fees, and fundraising. Other items included in our G&A expenses are legal and accounting expenses, investor relations fees, travel expenses, insurance, Sarbanes-Oxley (“SOX”) compliance expenses and other administrative expenses necessary for an operator of oil and gas properties as well as for the management a public company. For the year ended February 28, 2022, we received, as Operator of the East Slopes project in California, administrative overhead reimbursement of $53,287, which was used to directly offset certain employee salaries. We are continuing a program of reducing all of our G&A costs wherever possible. G&A expenses represented 64.1% and 67.1% of total operating expenses for the twelve months ended February 28, 2022 and February 28, 2021, respectively.

Interest expense, net decreased $17,728 or 7.5% to $220,085 for the twelve months ended February 28, 2022 in comparison to $237,813 for the twelve months ended February 28, 2021.

During the twelve months ended February 28, 2022, the Company recognized a gain on asset disposal of $9,614. The gain was the result of an insurance settlement on the theft of a company vehicle that was fully depreciated.

During the twelve months ended February 28, 2022, the Company recognized a gain on debt forgiveness in the amount of $72,800 due to notification that the SBA had approved the company's application for loan forgiveness on the PPP 2nd Draw loan. During the twelve months ended February 28, 2021, the Company recognized a gain on debt forgiveness in the amount of $74,355 due to notification that the SBA had approved the company's application for loan forgiveness on the PPP initial loan.

Due to the nature of our business, we expect that revenues, as well as all categories of expenses, will continue to fluctuate substantially quarter-to-quarter and year-to-year. Our revenues are dependent upon both hydrocarbon production levels and the price we receive for hydrocarbon sales. Production costs will fluctuate according to the number and percentage ownership of producing wells the period of time the wells have been producing, as well as the amount of revenues being generated by each well. Exploration and drilling expenses will be dependent upon the amount of capital that we have to invest in future development projects, as well as the success or failure of such projects. Likewise, the amount of DD&A expense will depend upon the factors cited above, plus the size of our proven reserve base and the market price of energy products. G&A expenses will also fluctuate based on our current requirements, but will generally tend to increase as we expand the business operations of the Company. An on-going goal of the Company is to improve cash flow to cover the current level of G&A expenses; to fund our development drilling in California; and, future drilling programs in other geographic locations.

Capital Resources and Liquidity

Our primary financial resource is our base of crude oil reserves. Our ability to fund our capital expenditure program is dependent upon the prices we receive from our crude oil and natural gas sales and the availability of capital resource financing. There continues to be a significant amount of volatility in hydrocarbon prices and a corresponding fluctuation in our realized sale price of crude oil does exist. An example of this volatility is that in June of 2014 the monthly average price of WTI crude oil was $105.79 per barrel and our realized price per barrel of crude oil was $98.78 while in April 2020, the monthly average price of WTI crude oil was $16.55 and our monthly realized price was $16.96 per barrel. Finally, in February 2022, the monthly average price of WTI oil was $91.64 per barrel and our realized price per barrel of crude oil was $87.41. This volatility in crude oil prices has continued throughout most of the fiscal year ended February 28, 2022. Any downward volatility in the price of crude oil will have a prolonged and substantial negative impact on our profitability and cash flow from our producing California properties. It is beyond our ability to accurately predict crude oil prices over any substantial length of time. When new financing is secured, we plan to drill four development wells for a total of $565,000.

Off-Balance Sheet Arrangements

As of February 28, 2022, we did not have any relationships with unconsolidated entities or financial partners, such as entities often referred to as structured finance or special purpose entities, which have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. As such, we are not materially exposed to any financing, liquidity, market or credit risk that could arise if we had engaged in such relationships.

Factors such as changes in operating margins and the availability of capital resources could increase or decrease our ultimate level of expenditures during the next fiscal year.

Changes in our capital resources at February 28, 2022 are set forth in the table below:

	February 28, 2022	February 28, 2021	Increase (Decrease)	Percentage Change
Cash	$ 139,573	$ 33,528	$ 106,045	316.3%
Current Assets	$ 416,651	$ 283,239	$ 133,412	47.1%
Total Assets	$ 975,704	$ 912,125	$ 63,579	7.0%
Current Liabilities	$ (3,404,735)	$ (4,469,074)	$ (1,064,339)	(23.8%)
Total Liabilities	$ (4,322,908)	$ (6,029,265)	$ (1,706,357)	(28.3%)
Working Capital Deficit	$ (2,988,084)	$ (4,185,835)	$ (1,197,751)	(28.6%)

Our working capital deficit decreased approximately $1.2 million or 28.6% from a deficit of approximately $4.2 million at February 28, 2021 to a deficit of approximately $3.0 million at February 28, 2022. The decrease in the working capital deficit was primarily due to a restructuring of our balance sheet by converting related party debt to common stock. This reduction was offset by an increase in accrued interest and the issuance of a short-term convertible note. For the twelve months ended February 28, 2022. we continued to have ongoing positive cash flow from our crude oil operations in California however, we were unable to generate sufficient cash flow to cover all of our general and administrative ("G&A") and interest expense requirements.

Our business is capital intensive. Our ability to grow is dependent upon favorably obtaining outside capital and generating cash flows from operating activities necessary to fund our investment activities. There is no assurance that we will be able to achieve profitability. Since our future operations will continue to be dependent on successful exploration and development activities and our ability to seek and secure capital from external sources, should we be unable to achieve sustainable profitability this could cause any equity investment in the Company to become worthless.

Major sources of funds in the past for us have included the debt or equity markets. We will have to rely on the capital markets to fund future operations and growth. Our business model is focused on acquiring exploration or development properties as well as existing production. Our ability to generate future revenues and operating cash flow will depend on successful exploration, and/or acquisition of crude oil and natural gas producing properties, which will require us to continue to raise equity or debt capital from outside sources.

Daybreak has ongoing capital commitments to develop certain leases pursuant to their underlying terms. Failure to meet such ongoing commitments may result in the loss of the right to participate in future drilling on certain leases or the loss of the lease itself. These ongoing capital commitments may also cause us to seek additional capital from sources outside of the Company. The current uncertainty in the credit and capital markets, as well as the instability and volatility in crude oil prices since June of 2014 has restricted our ability to obtain needed capital. No assurance can be given that we will be able to obtain funding under any loan commitments or any additional financing on favorable terms, if at all.

The Company's financial statements for the twelve months ended February 28, 2022 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. We have incurred a cumulative net loss since entering the crude oil and natural gas exploration industry in 2005. As of February 28, 2022, we have an accumulated deficit of approximately $29.5 million and a working capital deficit of approximately $3.0 million which raises substantial doubt about our ability to continue as a going concern.

On October 20, 2021, we entered into an Equity Exchange Agreement (the "Exchange Agreement") by and between Daybreak, Reabold California LLC, a California limited liability company ("Reabold"), and Gaelic Resources Ltd., a private company incorporated in the Isle of Man and the 100% owner of Reabold ("Gaelic"), pursuant to which the parties propose for (i) Daybreak to acquire 100% ownership of Reabold, in exchange for (ii) Daybreak issuing 160,964,489 shares of its common stock, par value $0.001 ("Common Stock") to Gaelic (the "Exchange Shares"), which will result in Reabold becoming a wholly-owned subsidiary of Daybreak named "Daybreak, LLC" and Gaelic becoming the owner of the Exchange Shares and a major shareholder of Daybreak (the foregoing transaction and the transactions contemplated thereby, the "Equity Exchange").

In connection with the Equity Exchange, and as conditions to closing the Equity Exchange, among other things we also propose to enter into agreements to sell a minimum of $2,500,000 of shares of Daybreak's Common Stock, and a minimum of 125,000,000 shares of Common Stock, to one or more investors in a private placement expected to close promptly following the closing of the Equity Exchange (the "Capital Raise"), with the proceeds of the Capital Raise to be used to repay in full the Company's line of credit with UBS Bank and for drilling and exploration activities and other working capital purposes.

As of February 28, 2022, all of the conditions for the closing of the Exchange Agreement have not yet been met. The Company is continuing to work towards satisfying all of the Exchange Agreement conditions including having certain conditions of the Exchange Agreement approved by the Company's shareholders. Please refer to Note 16 – Subsequent Events in the Notes to these financial statements.

Cash Flows

Changes in the net funds provided by or (used in) each of our operating, investing and financing activities are set forth in the table below:

	Twelve Months Ended February 28, 2022	Twelve Months Ended February 28, 2021	Increase (Decrease)	Percentage Change
Net cash (used in) operating activities	$ (13,356)	$ (143,526)	$ (130,170)	(90.7%)
Net cash (used in) investing activities	$ (16,232)	$ —	$ 16,232	100.0%
Net cash provided by financing activities	$ 135,633	$ 83,011	$ 52,622	63.4%

Cash Flow Used in Operating Activities

Cash flow from operating activities is derived from the production of our crude oil reserves and changes in the balances of non-cash accounts, receivables, payables or other non-energy property asset account balances. Cash flow used in our operating activities for the twelve months ended February 28, 2022 was $13,356 in comparison to cash flow used in our operating activities of $143,526 for the twelve months ended February 28, 2021. Changes in our cash flow operating activities for the twelve months ended February 28, 2022 in comparison to the twelve months ended February 28, 2021 were $130,170 and consisted of increases in our non-cash expenses of $21,650, primarily from recognition of impairment of Michigan unproved crude oil properties of $55,978; a decrease in changes in assets of $10,865; a decrease in changes in liabilities of $16,160 and the decrease in our net loss for the year of $113,815. Variations in cash flow from operating activities may impact our level of exploration and development expenditures.

Our expenditures in operating activities consist primarily of exploration and drilling expenses, production expenses, geological, geophysical and engineering services and maintenance of existing mineral leases. Our expenses also consist of consulting and professional services, employee compensation, legal, accounting, travel and other G&A expenses that we have incurred in order to address normal and necessary business activities of a public company in the crude oil exploration and production industry.

Cash Flow Used in Investing Activities

Cash flow from investing activities is derived from changes in oil and gas property balances, fixed asset balances and any lending activities. For the twelve months ended February 28, 2022 we used cash flow of $16,232 in comparison to no cash flow used for investing activities for the twelve months ended February 28, 2021.

Cash Flow Provided by Financing Activities

Cash flow from financing activities is derived from changes in long-term liability account balances or in equity account balances excluding retained earnings. Cash flow provided by our financing activities was $135,633 for the twelve months ended February 28, 2022 in comparison to $83,011 for the twelve months ended February 28, 2021. For the twelve months ended February 28, 2022, we received $72,800 in comparison to $74,355 for the twelve months ended February 28, 2021 under the paycheck protection program (PPP). For the twelve months ended February 28, 2022 and February 28, 2021, we made payments of $60,000, respectively, on the UBS Bank line of credit balances. We received $200,000 from a convertible note payable with a third party during the twelve months ended February 28, 2022. Finally, we made insurance premium financing payments of $68,568 and $74,553 during the twelve months ended February 28, 2022 and February 28, 2021, respectively. The following is a summary of the Company's financing activities for the twelve months ended February 28, 2022.

Debt (short-term and long-term borrowings)

Note Payable

In December 2018, the Company was able to settle an outstanding balance owed to one of its third-party vendors. This settlement resulted in a $120,000 note payable being issued to the vendor. Additionally, the Company agreed to issue 2,000,000 shares of the Company's common stock as a part of the settlement agreement. Based on the closing price of the Company's common stock on the date of the settlement agreement, the value of the common stock transaction was determined to be $6,000. The common stock shares were issued during the twelve months ended February 29, 2020. The note has a maturity date of January 1, 2022 and bears an interest rate of 10% rate per annum. Monthly interest is accrued and payable on January 1st of each anniversary date until maturity of the note. At February 28, 2022, the principal and accrued interest had not been paid and was outstanding. The accrued interest on the Note was $38,000 and $26,000 at February 28, 2022 and February 28, 2021, respectively.

Note Payable – Related Party

On December 22, 2020, the Company entered into a Secured Promissory Note (the "*Note*"), as borrower, with James Forrest Westmoreland and Angela Marie Westmoreland, Co-Trustees of the James and Angela Westmoreland Revocable Trust, or its assigns (the "*Noteholder*"), as the lender. James F. Westmoreland is the Company's Chairman, President and Chief Executive Officer. Pursuant to the Note, the Noteholder loaned the Company an aggregate principal amount of $155,548. After the deduction of loan fees of $10,929 the net proceeds from the loan were $144,619. The loan fees are being amortized as original issue discount (OID) over the term of the loan. The interest rate of the loan is 2.25%. The Note requires monthly payments on the Note balance until repaid in full. The maturity date of the Note is December 21, 2035. For the twelve months ended February 28, 2022, the Company made principal payments of $8,599 and amortized debt discount of $729. The obligations under the Note are secured by a lien on and security interest in the Company's oil and gas assets located in Kern County, California, as described in a Deed of Trust entered into by the Company in favor of the Noteholder to secure the obligations under the Note. Such lien shall be a first priority lien, subject only to a pre-existing lien filed by a working interest partner of the Company.

The Company may prepay the Note at any time. Upon the occurrence of any Event of Default and expiration of any applicable cure period, and at any time thereafter during the continuance of such Event of Default, the Noteholder may at its option, by written notice to the Company: (a) declare the entire principal amount of the Note, together with all accrued interest thereon and all other amounts payable hereunder, immediately due and payable; (b) exercise any of its remedies with respect to the collateral set forth in the Deed of Trust; and/or (c) exercise any or all of its other rights, powers or remedies under applicable law.

Current portion of note payable –related party balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
Note payable –related party, current portion	$ 8,829	$ 8,598
Unamortized debt issuance expenses	(729)	(728)
Note payable – related party, current portion, net	$ 8,100	$ 7,870

Note payable –related party long-term balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
Note payable – related party, non-current	$ 136,710	$ 145,540
Unamortized debt issuance expenses	(9,350)	(10,080)
Note payable – related party, non-current, net	$ 127,360	$ 135,460

Future estimated payments on the outstanding note payable – related party are set forth in the table below:

Twelve month periods ending February 28/29,	
2023	8,829
2024	9,065
2025	9,309
2026	9,558
2027	9,815
Thereafter	98,963
Total	$145,539

Short-term Convertible Note Payable

During the twelve months ended February 28, 2022, the Company executed a convertible promissory note with a third party for $200,000. The interest rate is 18% per annum and is payable in kind (PIK) solely by additional shares of the Company's common stock. Regardless of when conversion occurs, a full 12 months of interest will be payable upon conversion. The maturity date of the note is the date of the closing of the transactions contemplated by the Equity Exchange Agreement with Reabold California, LLC and Gaelic Resources, Ltd. as described above under the Capital Resources and Liquidity caption found in this Item 7, Management's Discussion and Analysis (MD&A). The conversion price was to be determined by one of two cases. In Case 1, the conversion price would be $0.017 and in Case 2, the conversion price would be $0.0085. The Case 1 conversion price scenario would apply if the terms of the Equity Exchange Agreement were met by a Long Stop Date of April 29, 2022. The Case 2 conversion price scenario would apply if the terms of the Equity Exchange Agreement were not met by a Long Stop Date of April 29, 2022. The terms of the Equity Exchange Agreement were not met by the Long Stop Date of April 29, 2022 and the conversion price was determined to be the $0.0085 rate. Under ASC 855-10-55-1, the Company determined that a derivate issue did not exist since the Company was able to determine the impact of the subsequent event.

On May 5, 2022, the Company received notice from the third party of their intent to convert the note principal and interest in the amount of $236,000 at the conversion price of $0.0085. Consequently, 27,764,706 shares of the Company's common stock were issued to the third party to satisfy the obligation.

12% Subordinated Notes

The Company's 12% Subordinated Notes ("the Notes") issued pursuant to a January 2010 private placement offering to accredited investors, resulted in $595,000 in gross proceeds (of which $250,000 was from a related party) to the Company and accrue interest at 12% per annum, payable semi-annually on January 29th and July 29th. On January 29, 2015, the Company and 12 of the 13 holders of the Notes agreed to extend the maturity date of the Notes for an additional two years to January 29, 2017. Effective January 29, 2017, the maturity date of the Notes was extended for an additional two years to January 29, 2019. The 980,000 warrants held by ten noteholders expired on January 29, 2019.

The Company has informed the Note holders that the payment of principal and final interest will be late and is subject to future financing being completed. The Notes principal of $565,000 was payable in full at the amended maturity date of the Notes, and has not been paid. Interest continues to accrue on the unpaid $565,000 principal balance. The terms of the Notes, state that should the Board of Directors, on any future maturity date, decide that the payment of the principal and any unpaid interest would impair the financial condition or operations of the Company, the Company may then elect a mandatory conversion of the unpaid principal and interest into the Company's common stock at a conversion rate equal to 75% of the average closing price of the Company's common stock over the 20 consecutive trading days preceding December 31, 2018.

As a result of the Company restructuring its balance sheet through conversions of debt to common stock, the related party 12% Noteholder chose to convert the principal and accrued interest of their Notes to the Company's common stock. The related party Note for $250,000 and accrued interest of $264,986 were converted to common stock at a rate of approximately $0.45 for every dollar of principal and interest resulting in 1,144,415 shares of common stock being issued. The accrued interest on the 12% Notes at February 28, 2022 and February 28, 2021 was $135,229 and $340,042, respectively.

12% Note balances at February 28, 2021 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
12% Subordinated notes – third party	$ 315,000	$ 315,000
12% subordinated notes – related party	—	250,000
12% Subordinated notes balance	$ 315,000	$ 565,000

The accrued interest at February 28, 2021 owed on the 12% Subordinated Note to the related party is presented on the Company's Balance Sheets under the caption *Accounts payable – related party* rather than under the caption *Accrued interest*.

Line of Credit

The Company has an existing $890,000 line of credit for working capital purposes with UBS Bank USA ("UBS"), established pursuant to a Credit Line Agreement dated October 24, 2011 that is secured by the personal guarantee of our President and Chief Executive Officer. On November 10, 2021, the Company was notified that effective January 1, 2022, a new interest rate benchmark the UBS Variable Rate (UBSVR) would replace the existing 30-day LIBOR ("London Interbank Offered Rate") benchmark. The UBSVR is comprised of the compounded 30-day average of the Secured Overnight Financing Rate (SOFR) plus a fixed spread adjustment of 0.110%. The Company's new all-on rate will consist of the UBSVR plus its current spread over LIBOR.

During the twelve months ended February 28, 2022 and February 28, 2021, we did not receive any advances on the line of credit, respectively. During the twelve months ended February 28, 2022 and February 28, 2021, we made payments to the line of credit of $60,000, respectively. Interest converted to principal for the twelve months ended February 28, 2022 and February 28, 2021 was $27,278 and $28,503, respectively. At February 28, 2022 and February 28, 2021, the line of credit had an outstanding balance of $808,182 and $840,904, respectively.

Production Revenue Payable

Since December 2018, the Company has been conducting a fundraising program to fund the drilling of future wells in California and to settle some of its existing historical debt. The purchasers of production payment interests receive a production revenue payment on future wells to be drilled in California in exchange for their purchase. On August 22, 2019, the Company entered into a Note Payoff Agreement with the Company's Chairman, President and Chief Executive Officer as payment in full of the $250,100 that had been loaned to the Company during the years ended February 29, 2012 and February 28, 2013. Pursuant to the Note Payoff Agreement, the Company issued a production payment interest in certain of the Company's production revenue from the drilling of future wells in California. The production payment interest was granted for a deemed consideration amount of the balance of the Notes. The grant was made on the same terms as the Company has sold production payment interests to other third parties in the 2018-2019 fiscal year pursuant to its previously disclosed program.

The production payment interest entitles the purchasers to receive production payments equal to twice their original amount paid, payable from a percentage of the Company's future net production payments from wells drilled after the date of the purchase and until the Production Payment Target (as described below) is met. The Company shall pay seventy-five percent (75%) of its net production payments from the relevant new wells to the purchasers until each purchaser has received two times the purchase price (the "Production Payment Target"). Once the Company pays the purchasers amounts equal to the Production Payment Target, it shall thereafter pay a pro-rated eight percent (8%) of $1.3 million on its net production payments from the relevant wells to each of the purchasers. However, if the total raised is less than the target $1.3 million, then the payment will be a proportionate amount of the eight percent (8%).

The Company accounted for the amounts received from these sales in accordance with ASC 470-10-25 and 470-10-35 which require amounts recorded as debt to be amortized under the interest method as described in ASC 835-30, Interest Method. Consequently, the program balance of $950,100 has been recognized as a production revenue payable. The Company determined an effective interest rate based on future expected cash flows to be paid to the holders of the production payment interests. This rate represents the discount rate that equates estimated cash flows with the initial proceeds received from the sales and is used to compute the amount of interest to be recognized each period. Estimating the future cash outflows under this agreement requires the Company to make certain estimates and assumptions about future revenues and payments and such estimates are subject to significant variability. Therefore, the estimates are likely to change which may result in future adjustments to the accretion of the interest expense and the amortized cost based carrying value of the related payables.

Accordingly, the Company has estimated the cash flows associated with the production revenue payments and determined a discount of $941,259 as of February 28, 2022, which is being accounted as interest expense over the estimated period over which payments will be made based on expected future revenue streams. For the twelve months ended February 28, 2022 and February 28, 2021, amortization of the debt discount on these payables amounted to $95,974 and $115,151, respectively, which has been included in interest expense in the statements of operations.

As a result of the Company restructuring its balance sheet through conversions of debt to common stock the related party with the production revenue interest chose to convert the original principal investment of $550,100 to the Company's common stock at a rate of approximately $0.45 for every dollar of principal and interest resulting in 1,222,444 shares of common stock being issued. The outstanding interest discount to debt of $232,170 was treated as a gain on debt forgives by the Company.

As of February 28, 2022 and February 28, 2021, the production revenue payment program balance was $817,125 and $1,503,422, respectively. Production revenue payable balances at February 28, 2020 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
Estimated payments of production revenue payable	$ 941,259	$ 2,000,258
Less: unamortized discount	(124,134)	(496,836)
	817,125	1,503,422
Less: current portion	(78,877)	(111,753)
Net production revenue payable – long term	$ 738,248	$ 1,391,669

Paycheck Protection Program (PPP) Loan

In March 2020, the Coronavirus Aid, Relief, and Economic Security Act commonly referred to as the CARES Act became law. One component of the CARES Act was the paycheck protection program ("PPP") which provides small business with the resources needed to maintain their payroll and cover applicable overhead. The PPP is implemented by the Small Business Administration ("SBA") with support from the Department of the Treasury. The Company applied for, and was accepted to participate in this program. On May 11, 2020, the Company received funding for approximately $74,355. On February 12, 2021, the Company applied for loan forgiveness under the provisions of Section 1106 of the CARES Act. Loan forgiveness was subject to the sole approval of the SBA. On February 23, 2021, the SBA notified our lender that the loan was forgiven and repaid the loan in full.

On March 4, 2021, the Company applied for, and was accepted to participate in the SBA PPP Second Draw program with funding pursuant to the Economic Aid Act that was passed in December, 2020. On March 15, 2021, Daybreak received funding for $72,800. The Company applied for full loan forgiveness for the PPP Second Draw PPP loan and on October 6, 2021, the SBA notified our lender that the loan was forgiven and repaid the loan in full.

Encumbrances

On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payable amounts owed to the partner by the Company.

Capital Commitments

Daybreak has ongoing capital commitments to develop certain oil and gas leases pursuant to their underlying terms. Failure to meet such ongoing commitments may result in the loss of the right to participate in future drilling on certain leases or the loss of the lease itself. These ongoing capital commitments may also cause us to seek additional capital from sources outside of the Company. The current uncertainty in the credit and capital markets, and the economic downturn, may restrict our ability to obtain needed capital.

Leases

The Company leases approximately 988 rentable square feet of office space from an unaffiliated third party for our corporate office located in Spokane Valley, Washington. Additionally, we lease approximately 416 and 695 rentable square feet from unaffiliated third parties for our regional operations office in Friendswood, Texas and storage and auxiliary office space in Wallace, Idaho, respectively. The lease in Friendswood is a 12-month lease that expires in October 2022 and as such is considered a short-term lease. The Company has elected to not apply the recognition requirements of ASC 842 to this short-term lease. The Spokane Valley and Wallace leases are currently on a month-to-month basis. The Company's lease agreements do not contain any residual value guarantees, restrictive covenants or variable lease payments. The Company has not entered into any financing leases.

Rent expense for the twelve months ended February 28, 2021 and February 28, 2021 was $23,489 and $23,589, respectively.

Crude Oil and Natural Gas Reserves

Daybreak's total net proved developed and undeveloped crude oil reserves on a per barrel of oil equivalent ("BOE") basis increased by 82,932 BOE, or 19.1%, to 517,155 BOE at February 28, 2022 compared to 434,223 BOE at February 28, 2021. These reserves are all located in our California East Slopes project. The primary reason for the overall increase in our total proven reserves was primarily due to higher hydrocarbon prices from the past year lowering the economic life our wells. The year-to-year reserve increase consisted of a 22,724 barrel or 23.9% increase in our PDP reserves and a 60,208 barrel or 17.8% increase in our PUD reserves. Our production of PDP reserves for the year ended February 28, 2022 was 9,613 BOE and was a part of the overall change in PDP reserves. The 82,932 increase in the PUD reserves was all due to upward revisions again because of higher crude oil prices in the past year. Our reserves were fully engineered by PGH Petroleum and Environmental Engineers, LLC of Austin, Texas in accordance with generally accepted petroleum engineering and evaluation principles and definitions and guidelines established by the SEC. For further information on our reserve report, refer to exhibit 99.1 of this Annual Report on Form 10-K.

Changes in Financial Condition

During the year ended February 28, 2022, we received crude oil sales revenue from 20 wells in our East Slopes Project in Kern County, California. Our commitment to improving corporate profitability remains unchanged. Since June 2014, there has been significant volatility in hydrocarbon prices and a corresponding fluctuation in our realized sale price of crude oil does exist. An example of this volatility is that in June of 2014 the monthly average price of WTI crude oil was $105.79 per barrel and our realized price per barrel of crude oil was $98.78 while in April 2020, the monthly average price of WTI crude oil was $16.55 and our monthly realized price was $16.96 per barrel. Finally, in February 2022, the monthly average price of WTI oil was $91.64 per barrel and our realized price per barrel of crude oil was $87.41. This volatility in crude oil prices has continued throughout most of the fiscal year ended February 28, 2022. Any downward volatility in the price of crude oil will have a prolonged and substantial negative impact on our profitability and cash flow from our producing California properties. It is beyond our ability to accurately predict crude oil prices over any substantial length of time. During the twelve months ended February 28, 2022 and February 28, 2021, crude oil revenue from California was $680,107 and $404,901, respectively. Of the $275,206 increase in revenue during the twelve months ended February 28, 2022, $371,212 or 134.9% can be attributed to the increase in our average realized crude oil sales price. For the twelve months ended February 28, 2022 and February 28, 2021, we had an operating loss of $260,780 and $348,807, respectively.

Our balance sheet at February 28, 2022 reflects total assets of approximately $0.98 million, an increase of approximately $63,000 in comparison to approximately $0.91 million at February 28, 2021. This increase of approximately $63,000 in total assets was due to an increase in current assets of approximately $133,000 offset by a decrease in long-term assets of approximately $70,000. Our cash balance increased by approximately $106,000.

At February 28, 2022, total liabilities were approximately $4.3 million, a decrease of approximately $1.7 million in comparison to approximately $6.0 million at February 28, 2021. This decrease was primarily due to conversion of related party debt to common stock through the restructuring of our balance sheet.

Common Stock shares issued and outstanding at February 28, 2022 and February 28, 2021 were 67,802,273 and 60,491,122, respectively. Of the total 7,311,151 shares issued during the twelve months ended February 28, 2022, there were 4,082,447 shares issued to satisfy related party debt. Another 3,228,704 shares were issued to satisfy the Series A Preferred stock conversion and associated accumulated dividend. The February 28, 2022 and February 28, 2021 balances of Series A Preferred Stock shares issued and outstanding were -0- and 709,568, respectively.

With the filing of our Second Amended and Restated Articles of Incorporation with the Washington Secretary of State in May 2022, the Company no longer has any preferred stock shares. We only have one class of stock and that is common stock.

Accumulated Deficit

Our financial statements for the twelve months ended February 28, 2022 and February 28, 2021 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. Our financial statements show that the Company has incurred significant operating losses that raise substantial doubt about our ability to continue as a going concern. The accompanying financial statements do not include any adjustments that might result from this uncertainty.

The increase of approximately $102,000 in the accumulated deficit from approximately $29.4 million at February 28, 2021 to $29.5 million at February 28, 2022 was due to the net loss for the year of approximately $398,450 offset by related party debt forgiveness of approximately $337,825 and issuance of the Series A Preferred stock accumulated divided of $29,480 and settlement of related party receivables and payables of $11,454.

Cash Balance

We maintain our cash balance by increasing or decreasing our exploration and drilling expenditures as limited by availability of cash from operations, investments and capital resource funding. Our cash balances were $139,573 and $33,528 at February 28, 2022 and February 28, 2021, respectively.

Crude oil and natural gas revenues

Crude oil revenues increased $275,206 or 68.0% to $680,107 for the twelve months ended February 28, 2022 in comparison to $404,901 for the twelve months ended February 28, 2021. Of the $275,206 increase in revenue during the twelve months ended February 28, 2022, $371,212 or 134.9% can be attributed to the increase in our average realized crude oil sales price.

Operating Expenses

Operating expenses for the twelve months ended February 28, 2022 increased $187,178 or 24.8% to approximately $940,886 in comparison to approximately $753,708 for the year ended February 28, 2021.

Operating Loss

For the twelve months ended February 28, 2022 and February 28, 2021, we reported operating losses of $260,779 and $348,807, respectively. The decrease in the operating loss for the twelve months ended February 28, 2022 of approximately $88,028 was primary due to increases in crude oil sales revenue due to higher energy prices.

Net Loss

Since entering the crude oil and natural gas exploration industry, we have incurred net losses with periodic negative cash flow and have depended on external financing and the sale of crude oil and natural gas assets to sustain our operations. For the twelve months ended February 28, 2022 we reported a net loss of $398,450 in comparison to net loss of $512,265 for the twelve months ended February 28, 2021.

<u>*Management Plans to Continue as a Going Concern*</u>

We continue to implement plans to enhance Daybreak's ability to continue as a going concern. The Company currently has a net revenue interest in 20 producing crude oil wells in our East Slopes Project located in Kern County, California. The revenue from these wells has created a steady and reliable source of revenue for the Company. Our average working interest in these wells is 36.6% and the average net revenue interest is 28.4%.

We anticipate revenues will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project in California. However given the current decline and instability in hydrocarbon prices, the timing of any drilling activity in California will be dependent on a sustained improvement in hydrocarbon prices and a successful refinancing or restructuring of our current credit facility.

We believe that our liquidity will improve when there is a sustained improvement in hydrocarbon prices. Our sources of funds in the past have included the debt or equity markets and the sale of assets. While the Company does have positive cash flow from its crude oil and natural gas properties, it has not yet established a positive cash flow on a company-wide basis. It will be necessary for the Company to obtain additional funding from the private or public debt or equity markets in the future. However, we cannot offer any assurance that we will be successful in executing the aforementioned plans to continue as a going concern.

On October 20, 2021, the Company entered into an Equity Exchange Agreement (the "Exchange Agreement") by and between Daybreak, Reabold California LLC, a California limited liability company ("Reabold"), and Gaelic Resources Ltd., a private company incorporated in the Isle of Man and the 100% owner of Reabold ("Gaelic"), pursuant to which the parties propose for (i) Daybreak to acquire 100% ownership of Reabold, in exchange for (ii) Daybreak issuing 160,964,489 shares of its common stock, par value $0.001 ("Common Stock") to Gaelic (the "Exchange Shares"), which will result in Reabold becoming a wholly-owned subsidiary of Daybreak and Gaelic becoming the owner of the Exchange Shares and a major shareholder of Daybreak (the foregoing transaction and the transactions contemplated thereby, the "Equity Exchange").

At a special meeting of shareholders held on May 20, 2022, shareholders approved the Equity Exchange Agreement between Daybreak, Reabold California, LLC ("Reabold") and Gaelic Resources, Ltd. ("Gaelic"). As a result of this approval, on May 25, 2022, the Company proceeded with the acquisition of Reabold and its producing crude oil and natural gas properties in California. The acquisition was completed by Daybreak issuing 160,964,489 common stock shares to Gaelic, along with the customary closing terms and conditions for acquisitions of this nature.

Also during the special meeting of shareholders, approval was granted to Amend and Restate the Company's Articles of Incorporation. This would allow for the increase in the number of authorized common stock shares of the Company from 200,000,000 shares to 500,000,000 shares. The increase in common stock shares will give the Company enough authorized common stock shares to complete the transaction with Reabold and Gaelic. Also, all the Preferred stock classification was eliminated.

In conjunction with the Company's efforts to acquire Reabold, and as a condition of closing the acquisition, the Company was to secure a capital raise of $2,500,000 through the issuance of shares of the Company's common stock. The commitment for that capital raise was executed on May 5, 2022, and subsequently 128,125,000 shares were issued.

Summary of Critical Accounting Policies and Estimates

Critical accounting policies are policies that are both most important to the portrayal of the Company's financial condition and results, and that require management's most difficult, subjective or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain. Management's discussion and analysis of our financial condition and results of operations are based on our financial statements, which have been prepared in conformity with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accounting estimates are considered to be critical if (1) the nature of the estimates and assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (2) the impact of the estimates and assumptions on financial condition or operating performance is material. Actual results could differ from the estimates and assumptions used.

On an ongoing basis, we evaluate our estimates, including those related to revenue recognition, bad debts, cancellation costs associated with long term commitments, investments, intangible assets, assets subject to disposal, income taxes, service contracts, contingencies and litigation. We base our estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making estimates and judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Estimates, by their nature, are based on judgment and available information. These judgments and uncertainties do affect the application of these critical accounting policies. There is a strong likelihood that materially different amounts could be reported under different conditions or using different assumptions. Therefore, actual results could differ from those estimates and could have a material impact on our financial statements, and it is possible that such changes could occur in the near term.

Proved Crude Oil and Natural Gas Reserves

Our estimates of proved and proved developed reserves are a major component of our depletion calculation. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. Proved reserves are defined by the SEC as those quantities of crude oil and natural gas which, by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or through installed extraction equipment and infrastructure operational at the time of the reserve estimates if the extraction is by means not involving a well.

Although our external engineers are knowledgeable of and follow the guidelines for reserves as established by the SEC, the estimation of reserves requires the engineers to make a significant number of assumptions based on professional judgment. Estimated reserves are often subject to future revision, certain of which could be substantial, based on the availability of additional information, including reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in crude oil and natural gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions inherently lead to adjustments of depreciation rates used by us. We cannot predict the types of reserve revisions that will be required in future periods.

While the estimates of our proved reserves at February 28, 2022 included in this report have been prepared based on what we and our independent reserve engineers believe to be reasonable interpretations of the SEC rules, those estimates could differ materially from our actual results.

Successful Efforts Accounting Method

We use the successful efforts method of accounting for natural gas and oil producing activities as opposed to the alternate acceptable full cost method. We believe that net assets and net income are more conservatively measured under the successful efforts method of accounting than under the full cost method, particularly during periods of active exploration. Costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized as incurred. All exploratory dry holes and geological and geophysical costs are charged against earnings during the periods they occur. Costs to drill exploratory wells that are unsuccessful in finding proved reserves are expensed as incurred. The geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred. Costs to operate and maintain wells and field equipment are expensed as incurred.

Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploration well costs and development costs (plus estimated future dismantlement, surface restoration, and property abandonment costs, net of equipment salvage values) are amortized in a similar fashion (by field) based on their proved developed reserves. Support equipment and other property and equipment are depreciated over their estimated useful lives.

Pursuant to Financial Accounting Standards Board Codification ("ASC") Topic 360, *"Property, Plant and Equipment,"* we review proved oil and natural gas properties and other long-lived assets for impairment. These reviews are predicated by events and circumstances, such as downward revision of the reserve estimates or commodity prices that indicate a decline in the recoverability of the carrying value of such properties. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amounts of the properties are reduced to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production, future capital expenditures and a risk-adjusted discount rate. The charge is included in DD&A.

Unproved crude oil and natural gas properties that are individually significant are also periodically assessed for impairment of value. For the twelve months ended February 28, 2022, our unproved properties in Michigan and the balance of $55,978 was written off to exploration expense. An impairment loss for unproved crude oil and natural gas properties is recognized at the time of impairment by providing an impairment allowance.

On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated DD&A with a resulting gain or loss recognized in income. Deposits and advances for services expected to be provided for exploration and development or for the acquisition of crude oil and natural gas properties are classified as long-term other assets.

Revenue Recognition

The Company recognizes revenue under ASC 606, *Revenue from Contracts with Customers* ("Topic 606"). Under Topic 606, revenue will generally be recognized upon delivery of our produced crude oil and natural gas volumes to our customers. Our customer sales contracts include only crude oil sales in California. Each unit (crude oil barrel) of commodity product represents a separate performance obligation which is sold at variable prices, determinable on a monthly basis. The pricing provisions of our crude oil contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, product quality and prevailing supply and demand conditions in the geographic areas in which we operate. We will allocate the transaction price to each performance obligation and recognize revenue upon delivery of the commodity product when the customer obtains control. Control of our produced crude oil volumes passes to our customers when the oil is measured by a trucking oil ticket. The Company has no control over the crude oil after this point and the measurement at this point dictates the amount on which the customer's payment is based. Our crude oil revenue stream includes volumes burdened by royalty and other joint owner working interests. Our revenues are recorded and presented on our financial statements net of the royalty and other joint owner working interests. Our revenue stream does not include any payments for services or ancillary items other than sale of crude oil. We record revenue in the month our crude oil production is delivered to the purchaser.

Suspended Well Costs

We account for any suspended well costs in accordance with FASB ASC Topic 932, "Extractive Activities – Oil and Gas" ("ASC 932"). ASC 932 states that exploratory well costs should continue to be capitalized if: (1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and (2) sufficient progress is made in assessing the reserves and the economic and operating feasibility of the well. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs.

In addition, ASC 932 requires annual disclosure of: (1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, (2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and (3) an aging of exploratory well costs suspended for greater than one year, designating the number of wells the aging is related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation.

Share Based Payments

Share based awards are accounted for under FASB Topic ASC 718, *"Compensation-Stock Compensation"* ("ASC 718"). ASC 718 requires compensation costs for all share-based payments granted to be based on the grant date fair value. The value of the portion of the award that is ultimately expected to vest is recognized as expense ratably over the requisite service periods.

See Note 3 - Summary of Significant Accounting Policies in the Company's financial statements for a full discussion of our significant accounting policies.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

As a smaller reporting company, we are not required to provide the information otherwise required by this Item.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of
Daybreak Oil and Gas, Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Daybreak Oil and Gas, Inc. (the "Company") as of February 28, 2022 and February 28, 2021, and the related statements of operations, changes in stockholders' deficit, and cash flows for the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of February 28, 2022 and February 28, 2021, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Going Concern Matter

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has suffered recurring losses from operations and has a net capital deficiency that raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the 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 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 financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

Critical audit matters, are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

/s/ MaloneBailey, LLP
www.malonebailey.com
We have served as the Company's auditor since 2006.
Houston, Texas
June 15, 2022

DAYBREAK OIL AND GAS, INC.
Balance Sheets
As of February 28, 2022 and February 28, 2021

	As of February 28, 2022	As of February 28, 2021
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 139,573	$ 33,528
Accounts receivable:		
Crude oil sales	117,727	108,993
Joint interest participants	85,339	79,411
Prepaid expenses and other current assets	74,012	61,307
Total current assets	416,651	283,239
OIL AND GAS PROPERTIES, successful efforts method, net		
Proved properties	536,032	556,456
Unproved properties	—	55,978
PREPAID DRILLING COSTS	16,452	16,452
Vehicles and Equipment, net	6,569	—
Total long-term assets	559,053	628,886
Total assets	$ 975,704	$ 912,125
LIABILITIES AND STOCKHOLDERS' DEFICIT		
CURRENT LIABILITIES:		
Accounts payable and other accrued liabilities	$ 1,649,119	$ 1,710,922
Accounts payable - related parties	49,228	988,966
Accrued interest	176,229	123,659
Note payable	120,000	120,000
Note payable - related party, current, net of unamortized discount of $729 and $728, respectively	8,100	7,870
Convertible Note payable, related party	200,000	—
12% Note payable	315,000	315,000
12% Note payable - related party	—	250,000
Line of credit	808,182	840,904
Production revenue payable, current, net of unamortized discount	78,877	111,753
Total current liabilities	3,404,735	4,469,074
LONG TERM LIABILITIES:		
Note payable - related party, net of current portion and net of unamortized discount of $9,350 and $10,080, respectively	127,360	135,460
Production revenue payable, net of current portion and net of unamortized discount	738,248	1,391,669
Asset retirement obligation	52,565	33,062
Total long-term liabilities	918,173	1,560,191
Total liabilities	4,322,908	6,029,265
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' DEFICIT:		
Preferred stock - 10,000,000 shares authorized, $0.001 par value;	—	—
Series A Convertible Preferred stock - 2,400,000 shares authorized, $0.001 par value, 6% cumulative dividends; 709,568 shares issued and outstanding	—	710
Common stock- 200,000,000 shares authorized; $0.001 par value, 67,802,273 and 60,491,122 shares issued and outstanding, respectively	67,802	60,491
Additional paid-in capital	26,115,450	24,250,556
Accumulated deficit	(29,530,456)	(29,428,897)
Total stockholders' deficit	(3,347,204)	(5,117,140)
Total liabilities and stockholders' deficit	$ 975,704	$ 912,125

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Operations
For the Twelve Months Ended February 28, 2022 and February 28, 2021

	Twelve Months Ended February 28, 2022	Twelve Months Ended February 28, 2021
REVENUE:		
Crude oil sales	$ 680,107	$ 404,901
OPERATING EXPENSES:		
Production	231,275	187,858
Exploration and drilling	56,213	83
Depreciation, depletion and amortization	49,590	60,063
General and administrative	603,808	505,704
Total operating expenses	940,886	753,708
OPERATING LOSS	(260,779)	(348,807)
OTHER INCOME (EXPENSE):		
Interest expense, net	(220,085)	(237,813)
Gain on asset disposal	9,614	—
Gain on debt forgiveness – SBA paycheck protection program (PPP) loan	72,800	74,355
Total other expenses	(137,671)	(163,458)
NET LOSS	(398,450)	(512,265)
Cumulative convertible preferred stock dividend requirement	—	(127,714)
NET LOSS AVAILABLE TO COMMON SHAREHOLDERS	$ (398,450)	$ (639,979)
NET LOSS PER COMMON SHARE		
Basic and diluted	$ (0.01)	$ (0.01)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING		
Basic and diluted	61,548,414	57,916,382

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Changes in Stockholders' Deficit
For the Twelve Months Ended February 28, 2022 and February 28, 2021

	Series A Convertible Preferred Stock		Common Stock		Additional Paid-In	Accumulated	
	Shares	Amount	Shares	Amount	Capital	Deficit	Total
BALANCE, FEBRUARY 29, 2020	709,568	$ 710	53,532,364	$ 53,532	$ 24,223,783	$ (28,916,632)	$ (4,638,607)
Issuance of common stock for:							
Convertible note payable – related party	—	$ —	6,958,758	$ 6,959	$ 20,876	$ —	$ 27,835
Recognition of warrants for:							
Investor relations services	—	$ —	—	$ —	$ 5,897	$ —	$ 5,897
Net Loss	—	$ —	—	$ —	$ —	$ (512,265)	$ (512,265)
BALANCE, FEBRUARY 28, 2021	709,568	$ 710	60,491,122	$ 60,491	$ 24,250,556	$ (29,428,897)	$ (5,117,140)
Issuance of common stock for:							
Conversion of accrued employee salaries			1,397,880	1,398	627,649	52,530	681,577
Conversion of accrued director fees			317,708	318	142,651		142,969
Conversion of 12% Note principal and interest – related party			1,144,415	1,144	513,842		514,986
Conversion of production revenue program principal – related party			1,222,444	1,222	548,878		550,100
Conversion of Series A preferred stock	(709,568)	(710)	2,128,704	2,129	(1,419)		—
Conversion of Series A accumulated dividend			1,100,000	1,100	28,380	(29,480)	—
Recognition of warrants for:							
Investor relations services					4,913		4,913
Debt forgiveness accrued salary - related party						53,125	53,125
Debt forgiveness production revenue program interest – related party						232,170	232,170
Settlement of receivables and payables – related party						(11,454)	(11,454)
Net Loss						(398,450)	(398,450)
BALANCE, FEBRUARY 28, 2022	—	$ —	67,802,273	$ 67,802	$ 26,115,450	$ (29,530,456)	$ (3,347,204)

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows
For the Twelve Months Ended February 28, 2022 and February 28, 2021

	Twelve Months Ended	
	February 28, 2022	February 28, 2021
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (398,450)	$ (512,265)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Gain on forgiveness of PPP 2nd draw and 1st draw loans, respectively	(72,800)	(74,355)
Depreciation, depletion and amortization	49,590	60,063
Impairment of unproved crude oil properties	55,978	—
Amortization of debt discount	96,703	115,272
Operating lease expense in conjunction with right of use asset	—	5,857
Warrants issued for investor relations services	4,913	5,897
Changes in assets and liabilities:		
Accounts receivable – crude oil and natural gas sales	(8,734)	(52,083)
Accounts receivable - joint interest participants	(5,928)	(41,045)
Prepaid expenses and other current assets	68,449	54,896
Accounts payable and other accrued liabilities	52,922	152,816
Accounts payable - related parties	64,153	69,078
Operating lease liability change in conjunction with right of use asset	—	(5,857)
Accrued interest	79,848	78,200
Net cash used in operating activities	(13,356)	(143,526)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to crude oil and natural gas properties	(6,772)	—
Purchase of fixed asset (used pickup truck)	(9,460)	—
Net cash used in investing activities	(16,232)	—
CASH FLOWS FROM FINANCING ACTIVITIES:		
Payments to line of credit	(60,000)	(60,000)
Proceeds from convertible note payable	200,000	74,553
Insurance financing repayments	(68,568)	(74,553)
Proceeds from note payable – related party	—	144,619
Payments to note payable – related party	(8,599)	(1,410)
Proceeds from SBA PPP 2nd draw loan and 1st draw loans, respectively	72,800	74,355
Net cash provided by financing activities	135,633	83,011
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	106,045	(60,515)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	33,528	94,043
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 139,573	$ 33,528
CASH PAID FOR:		
Interest	$ 14,446	$ 15,106
Income taxes	$ —	$ —

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
Statements of Cash Flows (continued)
For the Twelve Months Ended February 28, 2022 and February 28, 2021

	Twelve Months Ended	
	February 28, 2022	February 28, 2021
SUPPLEMENTAL CASH FLOW INFORMATION:		
ARO asset and liability increase due to changes in estimates	$ 10,929	$ 1,863
Unpaid additions to crude oil and natural gas properties	$ —	$ 11,871
Non-cash addition to line of credit due to monthly interest	$ 27,278	$ 28,503
Financing of insurance premiums	$ 81,154	$ 65,088
Forgiveness of production revenue payable interest	$ 232,170	$ —
Settlement of accrued employee salaries credited to common stock, APIC and accumulated deficit	$ 681,577	$ —
Settlement of accrued director fees credited to common stock and APIC	$ 142,969	$ —
Settlement of 12% Note – related party credited to common stock and APIC	$ 514,986	$ —
Settlement of production revenue program – related party credited to paid in capital	$ 550,100	$ —
Settlement of Series A accumulated dividend credited to additional paid in capital	$ 28,380	$ —
Common stock issued for related party debt	$ —	$ 27,835
Common stock issued for conversion of Series A preferred stock	$ 710	$ —
Common stock issued for Series A preferred accumulated dividend	$ 1,100	$ —
Debt forgiveness of related party accrued gross salary and employer payroll taxes	$ 53,125	$ —
Settlement of related party receivables and payables	$ 11,454	$ —
Reclassification of related party accounts payable to accounts payable	$ 66,719	$ —

The accompanying notes are an integral part of these financial statements

DAYBREAK OIL AND GAS, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 1 — ORGANIZATION AND BASIS OF PRESENTATION:

Originally incorporated as Daybreak Uranium, Inc., ("Daybreak Uranium") on March 11, 1955, under the laws of the State of Washington, Daybreak Uranium was organized to explore for, acquire, and develop mineral properties in the Western United States. In August 1955, the assets of Morning Sun Uranium, Inc. were acquired by Daybreak Uranium. In May 1964, Daybreak Uranium changed its name to Daybreak Mines, Inc. During 2005, management of the Company decided to enter the crude oil and natural gas exploration and production industry. On October 25, 2005, the Company's shareholders approved a name change from Daybreak Mines, Inc. to Daybreak Oil and Gas, Inc. (referred to herein as "Daybreak" or the "Company") to better reflect the business of the Company.

All of the Company's crude oil production is sold under contracts that are market-sensitive. Accordingly, the Company's financial condition, results of operations, and capital resources are highly dependent upon prevailing market prices of, and demand for, crude oil. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the control of the Company. These factors include the level of global demand for petroleum products, foreign supply of crude oil and natural gas, the establishment of and compliance with production quotas by crude oil-exporting countries, the relative strength of the U.S. dollar, weather conditions, the price and availability of alternative fuels, and overall economic conditions, both foreign and domestic, crude oil disputes between OPEC members; and national and international pandemics like the coronavirus outbreak.

NOTE 2 — GOING CONCERN:

Financial Condition

Daybreak's financial statements for the twelve months ended February 28, 2022 and February 28, 2021 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of liabilities in the normal course of business. Daybreak has incurred net losses since inception and has accumulated a deficit of approximately $29.5 million and a working capital deficit of approximately $3.0 million, which raises substantial doubt about the Company's ability to continue as a going concern.

Management Plans to Continue as a Going Concern

The Company continues to implement plans to enhance its ability to continue as a going concern. Daybreak currently has a net revenue interest in 20 producing crude oil wells in its East Slopes Project located in Kern County, California (the "East Slopes Project"). The revenue from these wells has created a steady and reliable source of revenue. The Company's average working interest in these wells is 36.6% and the average net revenue interest is 28.4% for these same wells.

In December 2019, the 2019 novel coronavirus ("COVID-19") surfaced in Wuhan, China. The World Health Organization declared a global emergency on January 30, 2020, with respect to the outbreak and several countries, including the United States, Japan, parts of Europe and Australia have initiated travel restrictions to and from China. The impacts of the outbreak are unknown and rapidly evolving. This widespread health crisis and the governmental restrictions associated with it, have adversely affected demand for crude oil, depressed crude oil prices, and affected our ability to access capital. These factors, in turn, have had a negative impact on our operations, and financial condition as evidenced by the unprecedented decline in crude oil prices and our revenues during this same time period.

On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security Act commonly referred to as the CARES Act became law. One component of the CARES Act was the paycheck protection program ("PPP") which provides small business with the resources needed to maintain their payroll and cover applicable overhead. The PPP is implemented by the Small Business Administration ("SBA") with support from the Department of the Treasury. The Company applied for, and was accepted to participate in this program. On May 11, 2020, the Company received funding for approximately $74,355. In February 2021, the Company applied for full loan forgiveness and later that month was notified by our lender that the SBA had forgiven our original loan in full. On March 15, 2021, the Company received $72,800 in funding through the SBA second draw paycheck protection program. Second Draw PPP loans can be used to help fund payroll costs, including benefits. Funds can also be used to pay for mortgage interest, rent and utilities over a 24 week period. The Company applied for full loan forgiveness on this PPP second draw loan and on October 6, 2021, and the SBA notified our lender that the loan was forgiven and repaid the loan in full.

On October 20, 2021, the Company entered into an Equity Exchange Agreement (the "Exchange Agreement") by and between Daybreak, Reabold California LLC, a California limited liability company ("Reabold"), and Gaelic Resources Ltd., a private company incorporated in the Isle of Man and the 100% owner of Reabold ("Gaelic"), pursuant to which the parties propose for (i) Daybreak to acquire 100% ownership of Reabold, in exchange for (ii) Daybreak issuing 160,964,489 shares of its common stock, par value $0.001 ("Common Stock") to Gaelic (the "Exchange Shares"), which will result in Reabold becoming a wholly-owned subsidiary of Daybreak and Gaelic becoming the owner of the Exchange Shares and a major shareholder of Daybreak (the foregoing transaction and the transactions contemplated thereby, the "Equity Exchange").

At a special meeting of shareholders held on May 20, 2022, shareholders approved the Equity Exchange Agreement between Daybreak, Reabold California, LLC ("Reabold") and Gaelic Resources, Ltd. ("Gaelic"). As a result of this approval, on May 25, 2022, the Company proceeded with the acquisition of Reabold and its producing crude oil and natural gas properties in California. The acquisition was completed by Daybreak issuing 160,964,489 common stock shares to Gaelic, along with the customary closing terms and conditions for acquisitions of this nature.

Also during the special meeting of shareholders, approval was granted to Amend and Restate the Company's Articles of Incorporation. This would allow for the increase in the number of authorized common stock shares of the Company from 200,000,000 shares to 500,000,000 shares. The increase in common stock shares will give the Company enough authorized common stock shares to complete the transaction with Reabold and Gaelic. Also, all the Preferred stock classification was eliminated.

In conjunction with the Company's efforts to acquire Reabold, and as a condition of closing the acquisition, the Company was to secure a capital raise of $2,500,000 through the issuance of shares of the Company's common stock. The commitment for that capital raise was executed on May 5, 2022, and subsequently 128,125,000 shares were issued.

As of February 28, 2022, all of the conditions for the closing of the Exchange Agreement had not yet been met. The Company was continuing to work towards satisfying all of the Exchange Agreement conditions including having certain conditions of the Exchange Agreement approved by the Company's shareholders. Please refer to Note 16 – Subsequent Events in the Notes to these financial statements.

The Company anticipates revenue will continue to increase as the Company participates in the drilling of more wells in the East Slopes Project in California. Daybreak's sources of funds in the past have included the debt or equity markets and the sale of assets. While the Company has experienced periodic revenue growth, which has resulted in positive cash flow from its crude oil and natural gas properties, it has not yet established a positive cash flow on a company-wide basis. It will be necessary for the Company to obtain additional funding from the private or public debt or equity markets in the future. However, the Company cannot offer any assurance that it will be successful in executing the aforementioned plans to continue as a going concern.

Daybreak's financial statements as of February 28, 2022 and February 28, 2021 do not include any adjustments that might result from the inability to implement or execute Daybreak's plans to improve our ability to continue as a going concern.

NOTE 3 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Cash and Cash Equivalents

Cash equivalents include demand deposits with banks and all highly liquid investments with original maturities of three months or less. The Company has in the past maintained balances in financial institutions where deposits may exceed the federally insured deposit limit of $250,000. The Company has not experienced any losses from such accounts and does not believe it is exposed to any significant credit risk on cash.

Accounts Receivable

The Company routinely assesses the recoverability of all material trade and other receivables. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. Actual write-offs may exceed the recorded allowance. Substantially all of the Company's trade accounts receivable result from crude oil in California or joint interest billings to its working interest partners in California. This concentration of customers and joint interest owners may impact the Company's overall credit risk as these entities could be affected by similar changes in economic conditions as well as other related factors. Trade accounts receivable are generally not collateralized. There were no allowances for doubtful accounts for the Company's trade accounts receivable at February 28, 2022 and February 28, 2021.

Crude Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for crude oil and natural gas property acquisition, exploration, development, and production activities. Costs to acquire mineral interests in crude oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized as incurred. Costs to drill exploratory wells that are unsuccessful in finding proved reserves are expensed as incurred. In addition, the geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred. Costs to operate and maintain wells and field equipment are expensed as incurred.

Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on estimated proved reserves. Capitalized exploration well costs and development costs (plus estimated future dismantlement, surface restoration, and property abandonment costs, net of equipment salvage values) are amortized in a similar fashion (by field) based on their estimated proved developed reserves. Support equipment and other property and equipment are depreciated over their estimated useful lives.

Pursuant to the provisions of Financial Accounting Standards Codification ("ASC") Topic 360, *"Property, Plant and Equipment"* the Company reviews proved crude oil and natural gas properties and other long-lived assets for impairment. These reviews are predicated by events and circumstances, such as downward revision of the reserve estimates or commodity prices that indicate a decline in the recoverability of the carrying value of such properties. The Company estimates the future cash flows expected in connection with the properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amounts of the properties exceed their estimated undiscounted future cash flows, the carrying amounts of the properties are reduced to their estimated fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production, future capital expenditures and a risk-adjusted discount rate. These estimates of future product prices may differ from current market prices of crude oil and natural gas. Any downward revisions to management's estimates of future production or product prices could result in an impairment of the Company's crude oil and natural gas properties in subsequent periods. Unproved crude oil and natural gas properties that are individually significant are also periodically assessed for impairment of value. An impairment loss for unproved crude oil and natural gas properties is recognized at the time of impairment by providing an impairment allowance.

For the twelve months ended February 28, 2022, the Company recognized an impairment of unproved properties in Michigan and wrote down the entire $55,978 balance in Michigan. For the twelve months ended February 28, 2021 the Company did not recognize any impairment of its properties.

On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated DD&A with a resulting gain or loss recognized in income.

Property and Equipment

Fixed assets are stated at cost. Depreciation on vehicles is provided using the straight-line method over expected useful lives of three years. Depreciation on machinery and equipment is provided using the straight-line method over expected useful life of three years. Depreciation of production facilities and natural gas pipelines are recorded using the unit-of-production method based on estimated reserves.

Long Lived Assets

The Company reviews long-lived assets and identifiable intangibles whenever events or circumstances indicate that the carrying amounts of such assets may not be fully recoverable. The Company evaluates the recoverability of long-lived assets by measuring the carrying amounts of the assets against the estimated undiscounted cash flows associated with these assets. If this evaluation indicates that the future undiscounted cash flows of certain long-lived assets are not sufficient to recover the assets' carrying value, the assets are adjusted to their fair values (based upon discounted cash flows).

Fair Value of Financial Instruments

The carrying value of short-term financial instruments including cash, receivables, prepaid expenses, accounts payable, and other accrued liabilities, short-term liabilities and the line of credit approximated their fair values due to the relatively short period to maturity for these instruments. The long-term notes payable approximates fair value since the related rates of interest approximate current market rates.

Share Based Payments

Stock awards are accounted for under FASB ASC Topic 718, *"Compensation-Stock Compensation"* ("ASC 718"). Under ASC 718, compensation for all share-based payment awards is based on estimated fair value at the grant date. The value of the portion of the award that is ultimately expected to vest is recognized as expense on a straight-line basis over the requisite service periods, if any.

The Company estimates the fair value of stock purchase warrants on the grant date using the Black-Scholes option pricing model ("Black-Scholes Model") as its method of valuation for warrant awards granted during the year. The Company's determination of fair value of warrant awards on the date of grant using an option-pricing model is affected by the Company's stock price, as well as assumptions regarding a number of subjective variables. These variables include, but are not limited to, the Company's expected price volatility over the term of the awards and discount rates assumed.

Earnings (Loss) per Share of Common Stock

Basic earnings (loss) per share of Common Stock is calculated by dividing net earnings (loss) available to common stockholders by the weighted average number of common shares issued and outstanding during the year. Diluted earnings per share is computed based on the weighted average number of common shares outstanding, increased by dilutive Common Stock equivalents. For the years ended February 28, 2022 and February 28, 2021, Common Stock equivalents are excluded from the calculations since their effect is anti-dilutive due to the Company's net loss.

Concentration of Credit Risk

Substantially all of the Company's accounts receivable result from crude oil sales in California or joint interest billings to its working interest partners in California. This concentration of customers and joint interest owners may impact the Company's overall credit risk as these entities could be affected by similar changes in economic conditions as well as other related factors.

At the Company's East Slopes project in California we deal with only one buyer for the purchase of all crude oil production. The Company has no natural gas production in California. At February 28, 2022 and February 28, 2021, this one individual customer represented 100.0% of crude oil sales receivable from operations. If this buyer is unable to resell its products or if they lose a significant sales contract then the Company may incur difficulties in selling its crude oil production.

The Company's accounts receivable in California for crude oil sales at February 28, 2022 and February 28, 2021, respectively are set forth in the table below.

		February 28, 2022		February 28, 2021	
Project	**Customer**	**Accounts Receivable Crude Oil Sales**	**Percentage**	**Accounts Receivable Crude Oil Sales**	**Percentage**
California – East Slopes Project (Crude oil)	Plains Marketing	$ 117,727	100.0%	$ 108,993	100.0%

Revenue Recognition

The Company recognizes revenue under ASC 606, *Revenue from Contracts with Customers* ("Topic 606"). Under Topic 606, revenue will generally be recognized upon delivery of our produced crude oil and natural gas volumes to our customers. Our customer sales contracts include only crude oil sales in California. Under Topic 606, each unit (crude oil barrel) of commodity product represents a separate performance obligation which is sold at variable prices, determinable on a monthly basis. The pricing provisions of our crude oil contracts are primarily tied to a market index with certain adjustments based on factors such as delivery, product quality and prevailing supply and demand conditions in the geographic areas in which we operate. We will allocate the transaction price to each performance obligation and recognize revenue upon delivery of the commodity product when the customer obtains control. Control of our produced crude oil volumes passes to our customers when the oil is measured by a trucking oil ticket. The Company has no control over the crude oil after this point and the measurement at this point dictates the amount on which the customer's payment is based. Our crude oil revenue stream includes volumes burdened by royalty and other joint owner working interests. Our revenues are recorded and presented on our financial statements net of the royalty and other joint owner working interests. Our revenue stream does not include any payments for services or ancillary items other than sale of crude oil. We record revenue in the month our crude oil production is delivered to the purchaser.

Asset Retirement Obligation ("ARO")

The Company follows the provisions of FASB ASC Topic 410, *"Asset Retirement and Environmental Obligations"* ("ASC 410"), which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This standard requires that the Company recognize the fair value of a liability for an asset retirement obligation ("ARO") in the period in which it is incurred. The ARO is capitalized as part of the carrying value of the assets to which it is associated, and depreciated over the useful life of the asset. The ARO and the related asset retirement cost are recorded when an asset is first drilled, constructed or purchased. The asset retirement cost is determined and discounted to present value using a credit-adjusted risk-free rate. After initial recording, the liability is increased for the passage of time, with the increase being reflected as accretion expense in the statements of operations. Subsequent adjustments in the cost estimate are reflected in the ARO liability and the amounts continue to be amortized over the useful life of the related long-lived assets.

Suspended Well Costs

The Company accounts for any suspended well costs in accordance with FASB ASC Topic 932, *"Extractive Activities – Oil and Gas*" ("ASC 932"). ASC 932 states that exploratory well costs should continue to be capitalized if: (1) a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and (2) sufficient progress is made in assessing the reserves and the economic and operating feasibility of the well. If the exploratory well costs do not meet both of these criteria, these costs should be expensed, net of any salvage value. Additional annual disclosures are required to provide information about management's evaluation of capitalized exploratory well costs.

In addition, ASC 932 requires annual disclosure of: (1) net changes from period to period of capitalized exploratory well costs for wells that are pending the determination of proved reserves, (2) the amount of exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling and (3) an aging of exploratory well costs suspended for greater than one year, designating the number of wells the aging is related to. Further, the disclosures should describe the activities undertaken to evaluate the reserves and the projects, the information still required to classify the associated reserves as proved and the estimated timing for completing the evaluation.

Income Taxes

The Company follows the provisions of FASB ASC Topic 740, *"Income Taxes*" ("ASC 740"). As required under ASC 740, the Company accounts for income taxes using an asset and liability approach, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial statements and tax bases of assets and liabilities at the applicable tax rates. A valuation allowance is utilized when it is more likely than not, that some portion of, or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment.

ASC 740 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Under ASC 740, the Company recognizes tax benefits only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that is greater than 50% (percent) likely to be realized upon settlement. A liability for "unrecognized tax benefits" is recorded for any tax benefits claimed in our tax returns that do not meet these recognition and measurement standards.

Use of Estimates and Assumptions

In preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management is required to make estimates and assumptions. These estimates and assumptions may affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and reported amounts of revenues and expenses during the reporting periods. Actual results could differ materially from those estimates. The accounting policies most affected by management's estimates and assumptions are as follows:

- The reliance on estimates of proved reserves to compute the provision for depreciation, depletion and amortization and to determine the amount of any impairment of proved properties;
- The valuation of unproved acreage and proved crude oil and natural gas properties to determine the amount of any impairment of crude oil and natural gas properties;

- Judgment regarding the productive status of in-progress exploratory wells to determine the amount of any provision for abandonment; and
- Estimates regarding the timing and cost of future abandonment obligations; and,
- Estimates regarding projected cash flows used in determining the production payable discount.

Recent Accounting Pronouncements

Accounting Standards Issued and Adopted

The Company does not believe that any recently issued effective pronouncements, or pronouncements issued but not yet effective, if adopted, would have a material effect on the Company's financial statements.

NOTE 4 — ACCOUNTS RECEIVABLE:

Accounts receivable consists primarily of receivables from the sale of crude oil production by the Company and receivables from the Company's working interest partners in crude oil projects in which the Company acts as Operator of the project.

Crude oil sales receivables balances of $117,727 and $108,993 at February 28, 2022 and February 28, 2021, represent crude oil sales that occurred in February 2022 and 2021, respectively.

Joint interest participant receivables balances of $85,339 and $79,411 at February 28, 2022 and February 28, 2021, respectively, represent amounts due from working interest partners in California, where the Company is the Operator.

There were no allowances for doubtful accounts for the Company's trade accounts receivable at February 28, 2022 and February 28, 2021.

NOTE 5 — CRUDE OIL PROPERTIES:

Crude oil property balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
Proved leasehold costs	$ 115,119	$ 115,119
Unproved leasehold costs	—	55,978
Costs of wells and development	2,309,628	2,291,924
Capitalized exploratory well costs	1,341,494	1,341,494
Total cost of oil and gas properties	3,766,241	3,804,515
Accumulated depletion, depreciation amortization and impairment	(3,230,209)	(3,192,081)
Oil and gas properties, net	$ 536,032	$ 612,434

For the twelve months ended February 28, 2022 and February 28, 2021, the Company recognized depletion expense of $38,125 and $56,013, respectively which is included in DD&A in the statement of operations. Impairment expense for the twelve months ended February 28, 2022 and February 28, 2021 was $55,978 and $-0-, respectively.

NOTE 6 — ASSET RETIREMENT OBLIGATION ("ARO")

The Company's financial statements reflect the provisions of ASC 410. The ARO primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. The Company determines the ARO on its crude oil and natural gas properties by calculating the present value of estimated cash flows related to the liability. As of February 28, 2022 and February 28, 2021, ARO obligations were considered to be long-term based on the estimated timing of the anticipated cash flows. For the twelve months ended February 28, 2022 and February 28, 2021, the Company recognized accretion expense of $8,574 and $4,050, respectively which is included in DD&A in the statements of operations.

Changes in the asset retirement obligations for the twelve months ended February 28, 2022 and February 28, 2021 are set forth in the table below.

	February 28, 2022	February 28, 2021
Asset retirement obligation, beginning of period	$ 33,062	$ 27,149
Accretion expense	8,574	4,050
Revisions to asset retirement obligation	10,929	1,863
Asset retirement obligation, end of period	$ 52,565	$ 33,062

NOTE 7 — ACCOUNTS PAYABLE:

On March 1, 2009, the Company became the operator for the East Slopes Project located in Kern County, California. Additionally, the Company then assumed certain original defaulting partners' approximate $1.5 million liability representing a 25% working interest in the drilling and completion costs associated with the East Slopes Project four earning wells program. The Company subsequently sold the 25% working interest on June 11, 2009. Approximately $244,849 of the $1.5 million default remains unpaid and is included in the February 28, 2022 and February 28, 2021 accounts payable balance. Payment of this liability has been delayed until the Company's cash flow situation improves. On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payables owed to the partner by the Company. At February 28, 2022 and February 28, 2021, the balance owed this working interest partner was $76,268 and $88,905, respectively and is included in the accounts payable balances. During the twelve months ended February 28, 2022, the Company worked to restructure its balance sheet. Employer payroll tax estimates of $52,530 and employee payroll tax estimates of $135,687 that had been recognized as a part of the accounts payable balances were eliminated either through debt forgiveness or conversion to 301,527 shares of the Company's common stock.

NOTE 8 — ACCOUNTS PAYABLE- RELATED PARTIES:

The February 28, 2022 and February 28, 2021 accounts payable – related parties balances of $49,228 and $988,966, respectively, were comprised primarily of deferred salaries of one of the Company's Executive Officers and certain employees; directors' fees; expense reimbursements; and deferred interest payments on a 12% Subordinated Notes owed to the Company's Chairman, President and Chief Executive Officer.

During the twelve months ended February 28, 2022, the Company worked to restructure its balance sheet through the conversion of related party debt to the Company's common stock. Accrued employee net salaries of approximately $493,359 were converted into 1,096,353 shares of common stock. Accrued director fees of $142,969 were converted into 317,708 shares of common stock. Additionally, $264,986 of 12% Note related party interest was converted into 588,859 shares of common stock.

NOTE 9 — SHORT-TERM AND LONG-TERM BORROWINGS:

Note Payable

In December 2018, the Company was able to settle an outstanding balance owed to one of its third-party vendors. This settlement resulted in a $120,000 note payable being issued to the vendor. Additionally, the Company agreed to issue 2,000,000 shares of the Company's common stock as a part of the settlement agreement. Based on the closing price of the Company's common stock on the date of the settlement agreement, the value of the common stock transaction was determined to be $6,000. The common stock shares were issued during the twelve months ended February 29, 2020. The note has a maturity date of January 1, 2022 and bears an interest rate of 10% rate per annum. Monthly interest is accrued and payable on January 1st of each anniversary date until maturity of the note. At February 28, 2022, the principal and accrued interest had not been paid and was outstanding. The accrued interest on the Note was $38,000 and $26,000 at February 28, 2022 and February 28, 2021, respectively.

Note Payable – Related Party

On December 22, 2020, the Company entered into a Secured Promissory Note (the "*Note*"), as borrower, with James Forrest Westmoreland and Angela Marie Westmoreland, Co-Trustees of the James and Angela Westmoreland Revocable Trust, or its assigns (the "*Noteholder*"), as the lender. James F. Westmoreland is the Company's Chairman, President and Chief Executive Officer.

Pursuant to the Note, the Noteholder loaned the Company an aggregate principal amount of $155,548. After the deduction of loan fees of $10,929 the net proceeds from the loan were $144,619. The loan fees are being amortized as original issue discount (OID) over the term of the loan. The interest rate of the loan is 2.25%. The Note requires monthly payments on the Note balance until repaid in full. The maturity date of the Note is December 21, 2035. For the twelve months ended February 28, 2022, the Company made principal payments of $8,599 and amortized debt discount of $729. The obligations under the Note are secured by a lien on and security interest in the Company's oil and gas assets located in Kern County, California, as described in a Deed of Trust entered into by the Company in favor of the Noteholder to secure the obligations under the Note. Such lien shall be a first priority lien, subject only to a pre-existing lien filed by a working interest partner of the Company.

The Company may prepay the Note at any time. Upon the occurrence of any Event of Default and expiration of any applicable cure period, and at any time thereafter during the continuance of such Event of Default, the Noteholder may at its option, by written notice to the Company: (a) declare the entire principal amount of the Note, together with all accrued interest thereon and all other amounts payable hereunder, immediately due and payable; (b) exercise any of its remedies with respect to the collateral set forth in the Deed of Trust; and/or (c) exercise any or all of its other rights, powers or remedies under applicable law.

Current portion of note payable –related party balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
Note payable –related party, current portion	$ 8,829	$ 8,598
Unamortized debt issuance expenses	(729)	(728)
Note payable – related party, current portion, net	$ 8,100	$ 7,870

Note payable –related party long-term balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

	February 28, 2022	February 28, 2021
Note payable – related party, non-current	$ 136,710	$ 145,540
Unamortized debt issuance expenses	(9,350)	(10,080)
Note payable – related party, non-current, net	$ 127,360	$ 135,460

Future estimated payments on the outstanding note payable – related party are set forth in the table below:

Twelve month periods ending February 28/29,	
2023	8,829
2024	9,065
2025	9,309
2026	9,558
2027	9,815
Thereafter	98,963
Total	$ 145,539

Short-term Convertible Note Payable

During the twelve months ended February 28, 2022, the Company executed a convertible promissory note with a third party for $200,000. The interest rate is 18% per annum and is payable in kind (PIK) solely by additional shares of the Company's common stock. Regardless of when conversion occurs, a full 12 months of interest will be payable upon conversion. The maturity date of the note is the date of the closing of the transactions contemplated by the Equity Exchange Agreement with Reabold California, LLC and Gaelic Resources, Ltd. as described above under the Capital Resources and Liquidity caption found in this Item 7, Management's Discussion and Analysis (MD&A). The conversion price was to be determined by one of two cases. In Case 1, the conversion price would be $0.017 and in Case 2, the conversion price would be $0.0085. The Case 1 conversion price scenario would apply if the terms of the Equity Exchange Agreement were met by a Long Stop Date of April 29, 2022. The Case 2 conversion price scenario would apply if the terms of the Equity Exchange Agreement were not met by a Long Stop Date of April 29, 2022. The terms of the Equity Exchange Agreement were not met by the Long Stop Date of April 29, 2022 and the conversion price was determined to be the $0.0085 rate. Under ASC 855-10-55-1, the Company determined that a derivate issue did not exist since the Company was able to determine the impact of the subsequent event.

On May 5, 2022, the Company received notice from the third party of their intent to convert the note principal and interest in the amount of $236,000 at the conversion price of $0.0085. Consequently, 27,764,706 shares of the Company's common stock were issued to the third party to satisfy the obligation.

12% Subordinated Notes

The Company's 12% Subordinated Notes ("the Notes") issued pursuant to a January 2010 private placement offering to accredited investors, resulted in $595,000 in gross proceeds (of which $250,000 was from a related party) to the Company and accrue interest at 12% per annum, payable semi-annually on January 29th and July 29th. On January 29, 2015, the Company and 12 of the 13 holders of the Notes agreed to extend the maturity date of the Notes for an additional two years to January 29, 2017. Effective January 29, 2017, the maturity date of the Notes was extended for an additional two years to January 29, 2019. The 980,000 warrants held by ten noteholders expired on January 29, 2019.

The Company has informed the Note holders that the payment of principal and final interest will be late and is subject to future financing being completed. The Notes principal of $565,000 was payable in full at the amended maturity date of the Notes, and has not been paid. Interest continues to accrue on the unpaid $565,000 principal balance. The terms of the Notes, state that should the Board of Directors, on any future maturity date, decide that the payment of the principal and any unpaid interest would impair the financial condition or operations of the Company, the Company may then elect a mandatory conversion of the unpaid principal and interest into the Company's common stock at a conversion rate equal to 75% of the average closing price of the Company's common stock over the 20 consecutive trading days preceding December 31, 2018.

As a result of the Company restructuring its balance sheet through conversions of related party debt to common stock, the related party 12% Noteholder chose to convert the principal and accrued interest of their Notes to the Company's common stock. The related party Note for $250,000 and accrued interest of $264,986 were converted to common stock at a rate of approximately $0.45 for every dollar of principal and interest resulting in 1,144,415 shares of common stock being issued. The accrued interest on the 12% Notes at February 28, 2022 and February 28, 2021 was $135,229 and $340,042, respectively.

12% Note balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

	February 28, 2022		February 28, 2021	
12% Subordinated notes – third party	$	315,000	$	315,000
12% subordinated notes – related party		—		250,000
12% Subordinated notes balance	$	315,000	$	565,000

The accrued interest at February 28, 2021 owed on the 12% Subordinated Note to the related party is presented on the Company's Balance Sheets under the caption *Accounts payable – related party* rather than under the caption *Accrued interest*.

Line of Credit

The Company has an existing $890,000 line of credit for working capital purposes with UBS Bank USA ("UBS"), established pursuant to a Credit Line Agreement dated October 24, 2011 that is secured by the personal guarantee of our President and Chief Executive Officer. On November 10, 2021, the Company was notified that effective January 1, 2022, a new interest rate benchmark the UBS Variable Rate (UBSVR) would replace the existing 30-day LIBOR ("London Interbank Offered Rate") benchmark. The UBSVR is comprised of the compounded 30-day average of the Secured Overnight Financing Rate (SOFR) plus a fixed spread adjustment of 0.110%. The Company's new all-on rate will consist of the UBSVR plus its current spread over LIBOR.

During the twelve months ended February 28, 2022 and February 28, 2021, we did not receive any advances on the line of credit, respectively. During the twelve months ended February 28, 2022 and February 28, 2021, we made payments to the line of credit of $60,000, respectively. Interest converted to principal for the twelve months ended February 28, 2022 and February 28, 2021 was $27,278 and $28,503, respectively. At February 28, 2022 and February 28, 2021, the line of credit had an outstanding balance of $808,182 and $840,904, respectively.

Production Revenue Payable

Since December 2018, the Company has been conducting a fundraising program to fund the drilling of future wells in California and to settle some of its existing historical debt. The purchasers of production payment interests receive a production revenue payment on future wells to be drilled in California in exchange for their purchase. On August 22, 2019, the Company entered into a Note Payoff Agreement with the Company's Chairman, President and Chief Executive Officer as payment in full of the $250,100 that had been loaned to the Company during the years ended February 29, 2012 and February 28, 2013. Pursuant to the Note Payoff Agreement, the Company issued a production payment interest in certain of the Company's production revenue from the drilling of future wells in California. The production payment interest was granted for a deemed consideration amount of the balance of the Notes. The grant was made on the same terms as the Company has sold production payment interests to other third parties in the 2018-2019 fiscal year pursuant to its previously disclosed program.

The production payment interest entitles the purchasers to receive production payments equal to twice their original amount paid, payable from a percentage of the Company's future net production payments from wells drilled after the date of the purchase and until the Production Payment Target (as described below) is met. The Company shall pay seventy-five percent (75%) of its net production payments from the relevant wells to the purchasers until each purchaser has received two times the purchase price (the "Production Payment Target"). Once the Company pays the purchasers amounts equal to the Production Payment Target, it shall thereafter pay a pro-rated eight percent (8%) of $1.3 million on its net production payments from the relevant wells to each of the purchasers. However, if the total raised is less than the target $1.3 million, then the payment will be a proportionate amount of the eight percent (8%). At February 28, 2022, the Production Payment Target has not been met within the original three years and all future payments will be at the seventy-five percent (75%) rate.

The Company accounted for the amounts received from these sales in accordance with ASC 470-10-25 and 470-10-35 which require amounts recorded as debt to be amortized under the interest method as described in ASC 835-30, Interest Method. Consequently, the program balance of $950,100 has been recognized as a production revenue payable. The Company determined an effective interest rate based on future expected cash flows to be paid to the holders of the production payment interests. This rate represents the discount rate that equates estimated cash flows with the initial proceeds received from the sales and is used to compute the amount of interest to be recognized each period. Estimating the future cash outflows under this agreement requires the Company to make certain estimates and assumptions about future revenues and payments and such estimates are subject to significant variability. Therefore, the estimates are likely to change which may result in future adjustments to the accretion of the interest expense and the amortized cost based carrying value of the related payables.

Accordingly, the Company has estimated the cash flows associated with the production revenue payments and determined a discount of $941,259 as of February 28, 2022, which is being accounted as interest expense over the estimated period over which payments will be made based on expected future revenue streams. For the twelve months ended February 28, 2022 and February 28, 2021, amortization of the debt discount on these payables amounted to $95,974 and $115,151, respectively, which has been included in interest expense in the statements of operations.

As a result of the Company restructuring its balance sheet through conversions of debt to common stock the related party with the production revenue interest chose to convert the original principal investment of $550,100 to the Company's common stock at a rate of approximately $0.45 for every dollar of principal and interest resulting in 1,222,444 shares of common stock being issued. The outstanding interest discount to debt of $232,170 was treated as a gain on debt forgiveness by the Company.

As of February 28, 2022 and February 28, 2021, the production revenue payment program balance was $400,000 and $950,100, respectively. Production revenue payable balances at February 28, 2022 and February 28, 2021 are set forth in the table below:

		February 28, 2022		February 28, 2021
Estimated payments of production revenue payable	$	941,259	$	2,000,258
Less: unamortized discount		(124,134)		(496,836)
		817,125		1,503,422
Less: current portion		(78,877)		(111,753)
Net production revenue payable – long term	$	738,248	$	1,391,669

Paycheck Protection Program (PPP) Loan

In March 2020, the Coronavirus Aid, Relief, and Economic Security Act commonly referred to as the CARES Act became law. One component of the CARES Act was the paycheck protection program ("PPP") which provides small business with the resources needed to maintain their payroll and cover applicable overhead. The PPP is implemented by the Small Business Administration ("SBA") with support from the Department of the Treasury. The Company applied for, and was accepted to participate in this program. On May 11, 2020, the Company received funding for approximately $74,355. On February 12, 2021, the Company applied for loan forgiveness under the provisions of Section 1106 of the CARES Act. Loan forgiveness was subject to the sole approval of the SBA. On February 23, 2021, the SBA notified our lender that the loan was forgiven and repaid the loan in full.

On March 4, 2021, the Company applied for, and was accepted to participate in the SBA PPP Second Draw program with funding pursuant to the Economic Aid Act that was passed in December, 2020. On March 15, 2021, Daybreak received funding for $72,800. The Company applied for full loan forgiveness for the PPP Second Draw PPP loan and on October 6, 2021, the SBA notified our lender that the loan was forgiven and repaid the loan in full.

Encumbrances

On October 17, 2018, a working interest partner in California filed a UCC financing statement in regards to payable amounts owed to the partner by the Company.

NOTE 10 — LEASES:

The Company leases approximately 988 rentable square feet of office space from an unaffiliated third party for our corporate office located in Spokane Valley, Washington. Additionally, we lease approximately 416 and 695 rentable square feet from unaffiliated third parties for our regional operations office in Friendswood, Texas and storage and auxiliary office space in Wallace, Idaho, respectively. The lease in Friendswood is a 12-month lease that expires in October 2021 and as such is considered a short-term lease. The Company has elected to not apply the recognition requirements of ASC 842 to this short-term lease. The Spokane Valley and Wallace leases are currently on a month-to-month basis. The Company's lease agreements do not contain any residual value guarantees, restrictive covenants or variable lease payments. The Company has not entered into any financing leases.

Rent expense for the twelve months ended February 28, 2022 and February 28, 2021 was $23,489 and $23,589, respectively.

NOTE 11 — RELATED PARTY TRANSACTIONS:

The Company's Chief Operating Officer, Bennett Anderson is fifty percent (50%) owner in Great Earth Power, a company that provides a portion of the electrical service to Daybreak for its production operations at the East Slopes Project in Bakersfield, California. Great Earth Power began providing solar powered electricity for the production operations in California in September 2020. For the twelve months ended February 28, 2022 and February 28, 2021, Mr. Anderson received approximately $11,507 and $9,000, respectively from Great Earth Power.

Mr. Anderson is also a fifty percent (50%) owner in ABPlus Net Holdings, a company that provides tank rentals to Daybreak for its production operations in Kern County, California. The Company began renting tanks from ABPlus Net Holdings in November 2020. For the twelve months ended February 28, 2022 and February 28, 2021, Mr. Anderson received approximately $6,720 and $2,440, respectively from ABPlus Net Holdings.

NOTE 12 — STOCKHOLDERS' DEFICIT:

Preferred Stock

The Company is authorized to issue up to 10,000,000 shares of preferred stock with a par value of $0.001. The Company's preferred stock may be entitled to preference over the common stock with respect to the distribution of assets of the Company in the event of liquidation, dissolution, or winding-up of the Company, whether voluntarily or involuntarily, or in the event of any other distribution of assets of the Company among its shareholders for the purpose of winding-up its affairs. The authorized but unissued shares of preferred stock may be divided into and issued in designated series from time to time by one or more resolutions adopted by the Board of Directors. The directors in their sole discretion shall have the power to determine the relative powers, preferences, and rights of each series of preferred stock.

With the filing of the Company's Second Amended and Restated Articles of Incorporation with the Washington Secretary of State in May 2022, the Company no longer has any preferred stock shares. The Company has only one class of stock and that is common stock.

Series A Convertible Preferred Stock

The Company has designated 2,400,000 shares of the 10,000,000 preferred shares as Series A Convertible Preferred Stock ("Series A Preferred"), with a $0.001 par value. In July 2006, the Company completed a private placement of the Series A Preferred that resulted in the issuance of 1,399,765 shares to 100 accredited investors.

The terms of the Series A Preferred are disclosed in the Company's Amended and Restated Articles of Incorporation. Conversion of Series A Preferred to the Company's Common Stock by the accredited investors relies upon an exemption from registration provided by Section 3(a)(9) of the Securities Act of 1933 relating to securities exchanged by the issuer with its existing security holders exclusively where no commission or other remuneration is paid or given directly or indirectly for soliciting such exchange.

During the twelve months ended February 28, 2022, the Company proposed to all 56 remaining Series A shareholders, who had not previously converted to the Company's common stock, the conversion of their Series A shares into three shares of the Company's common stock. Included with this proposal, the Company offered to pay any accrued Series A dividend, on a pro rata basis, with 1,100,000 shares of common stock. In order for the conversion to occur and the dividend to be paid, a majority of the Series A shares had to vote to accept the conversion proposal. With a majority of 53.6%, the outstanding shares voted in favor of the conversion and dividend issuance. There were 46.4% of the outstanding shares who chose to vote no; not to vote or had their notices of the conversion vote returned to the Company as an invalid address. As a result of the affirmative vote, 709,568 shares of Series A Preferred stock was converted to 2,128,704 shares of common stock and 1,100,000 shares of common stock were issued to satisfy the accumulated dividend of $2,449,979. At February 28, 2022, there were no outstanding shares of Series A Preferred stock remaining.

The following is a summary of the rights and preferences of the Series A Preferred.

Conversion:

At February 28, 2022, there were no shares issued and outstanding that had not been converted into our Common Stock. As of February 28, 2021, there were 44 accredited investors who had converted 690,197 Series A Preferred shares into 2,070,591 shares of Daybreak Common Stock.

The conversions of Series A Preferred that have occurred since the Series A Preferred was first issued in July 2006 are set forth in the table below.

Fiscal Period	Shares of Series A Preferred Converted to Common Stock	Shares of Common Stock Issued from Conversion	Number of Accredited Investors
Year Ended February 29, 2008	102,300	306,900	10
Year Ended February 28, 2009	237,000	711,000	12
Year Ended February 28, 2010	51,900	155,700	4
Year Ended February 28, 2011	102,000	306,000	4
Year Ended February 29, 2012	—	—	—
Year Ended February 28, 2013	18,000	54,000	2
Year Ended February 28, 2014	151,000	453,000	9
Year Ended February 28, 2015	3,000	9,000	1
Year Ended February 29, 2016	10,000	30,000	1
Year Ended February 28, 2017	—	—	—
Year Ended February 28, 2018	14,997	44,991	1
Year Ended February 28, 2019	—	—	—
Year Ended February 29, 2020	—	—	—
Year Ended February 28, 2021	—	—	—
Year Ended February 28, 2022	709,568	2,128,704	56
Totals	1,399,765	4,199,295	100

Dividends:

Holders of Series A Preferred shall be paid dividends, in the amount of 6% of the original purchase price per annum. Dividends may be paid in cash or Common Stock at the discretion of the Company. Dividends are cumulative from the date of the final closing of the private placement, whether or not in any dividend period or periods we have assets legally available for the payment of such dividends. Accumulations of dividends on shares of Series A Preferred do not bear interest. Dividends are payable upon declaration by the Board of Directors. During the twelve months ended February 28, 2022, all accumulated dividends of $2,449,979 were paid through the issuance of 1,100,000 shares of common stock.

Cumulative dividends earned for each twelve month period since issuance are set forth in the table below:

Fiscal Year Ended	Shareholders at Period End	Accumulated Dividends
February 28, 2007	100	$ 155,311
February 29, 2008	90	242,126
February 28, 2009	78	209,973
February 28, 2010	74	189,973
February 28, 2011	70	173,707
February 29, 2012	70	163,624
February 28, 2013	68	161,906
February 28, 2014	59	151,323
February 28, 2015	58	132,634
February 29, 2016	57	130,925
February 28, 2017	57	130,415
February 28, 2018	56	128,231
February 28, 2019	56	127,714
February 29, 2020	56	128,063
February 28, 2021	56	127,714
February 28, 2022	—	96,340
		$ 2,449,979

At a special meeting of shareholders on May 20, 2022 the Company's shareholders approved the Second Amended and Restated Articles of Incorporation, which eliminates the classification of the Series A Preferred.

Common Stock

The Company is authorized to issue up to 200,000,000 shares of $0.001 par value Common Stock of which 67,802,273 and 60,491,122 shares were issued and outstanding as of February 28, 2022 and February 28, 2021, respectively.

	Common Stock Balance		Par Value
Common stock, Issued and Outstanding, February 28, 2019	51,532,364		
Share issuances during the twelve months ended February 29, 2020	2,000,000	$	2,000
Common stock, Issued and Outstanding, February 29, 2020	53,532,364		
Share issuances during the twelve months ended February 28, 2021	6,958,758	$	6,959
Common stock, Issued and Outstanding, February 28, 2021	60,491,122		
Shares issued for Series A Preferred conversion	2,128,704	$	2,129
Shares issued for Series A accumulated dividend	1,100,000	$	1,100
Shares issued for debt conversion of accrued salaries	1,397,880	$	1,398
Shares issued for debt conversion of accrued directors fees	317,708	$	318
Shares issued for conversion of 12% Note principal and interest – related party	1,144,415	$	1,144
Shares issued for investment principal in production revenue program	1,222,444	$	1,222
Common stock, Issued and Outstanding, February 28, 2022	67, 802,273		

During the twelve months ended February 28, 2022, there were 7,311,151 shares of common stock issued as a part of the Company's restructuring of its balance sheet in accordance with the conditions of the Equity Exchange Agreement between Reabold California, LLC, Gaelic Resources Ltd, and the Company. Of the total 7,311,151 shares issues, there were 4,082,447 shares issued to satisfy related party debt. Another 3,228,704 shares were issued to satisfy the Series A Preferred stock conversion and associated accumulated dividend of $2,449,979. During the twelve months ended February 28, 2021, there were 6,958,758 shares of common stock shares valued at $27,835 issued to a related party to settle a note payable.

All shares of Common Stock are equal to each other with respect to voting, liquidation, dividend and other rights. Owners of shares of Common Stock are entitled to one vote for each share of Common Stock owned at any shareholders' meeting. Holders of shares of Common Stock are entitled to receive such dividends as may be declared by the Board of Directors out of funds legally available therefore; and upon liquidation, are entitled to participate pro rata in a distribution of assets available for such a distribution to shareholders.

There are no conversion, preemptive, or other subscription rights or privileges with respect to any shares of our Common Stock. Our stock does not have cumulative voting rights, which means that the holders of more than 50% of the shares voting in an election of directors may elect all of the directors if they choose to do so. In such event, the holders of the remaining shares aggregating less than 50% would not be able to elect any directors.

At a special meeting of shareholders on May 20, 2022 the Company's shareholders approved an increase in the number of authorized common stock shares to 500,000,000 rather than the previous 200,000,000 common stock authorization.

NOTE 13 — WARRANTS:

During the twelve months ended February 29, 2020 there were 2.1 million warrants issued to a third party for investor relations services. The fair value of the warrants was determined by the Black-Scholes pricing model, was $17,689, and is being amortized over the three year vesting period of the warrants. The Black-Scholes valuation encompassed the following assumptions: a risk-free interest rate of 1.68%; volatility rate of 260.23%; and a dividend yield of 0.0%.

The warrant contains a vesting blocking provision that prevents the vesting of any warrants that such vesting would cause the warrant holder's beneficial ownership (as such term is defined in Section 13d-3 of the Securities Exchange Act of 1934, as amended) to exceed more than four and ninety-nine one-hundredths percent (4.99%) of the Company's outstanding Common Stock. The foregoing restriction may not be waived by either party. The warrants vest in equal parts over a three year period beginning on January 2, 2020 and all warrants expire on January 2, 2024.

As of February 28, 2022 and February 28, 2021, there were 893,333 and 528,507 exercisable warrants. At February 28, 2022, both the outstanding warrants and the exercisable warrants had a weighted average exercise price of $0.01; a weighted average remaining life of 1.84 years, and an intrinsic value of $20,265. The recorded amount of warrant expense for the twelve months ended February 28, 2022 and February 28, 2021 was $4,913 and $5,897, respectively.

Warrant activity for the twelve months ended February 28, 2022 and February 28, 2021 is set forth in the table below:

	Warrants		Weighted Average Exercise Price
Warrants outstanding, February 29, 2020	2,100,000	$	0.01
Changes during the twelve months ended February 28,2021:			
Issued	—		
Expired / Cancelled / Forfeited	—		
Warrants outstanding, February 28. 2021	2,100,000	$	0.01
Warrants exercisable, February 28, 2021	528,507		
Changes during the twelve months ended February 28, 2022:			
Issued	—	$	
Expired / Cancelled / Forfeited	—		
Warrants outstanding, February 28, 2022	2,100,000	$	0.01
Warrants exercisable, February 28, 2022	893,333	$	0.01

NOTE 14 — INCOME TAXES:

On December 22, 2017, the federal government enacted a tax bill H.R.1, an act to provide for reconciliation pursuant to Titles II and V of the concurrent resolution on the budget for fiscal year 2018, commonly referred to as the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act contains significant changes to corporate taxation, including, but not limited to, reducing the U.S. federal corporate income tax rate from 35% to 21% and modifying or limiting many business deductions. The Company has re-measured its deferred tax liabilities based on rates at which they are expected to be utilized in the future, which is generally 21%.

Reconciliation between actual tax expense (benefit) and income taxes computed by applying the U.S. federal income tax rate and state income tax rate to income from continuing operations before income taxes is as follows:

		February 28, 2022		February 28, 2021
Computed at U.S. and state statutory rates	$	(118,897)	$	(152,860)
Permanent differences		11,157		15,342
Changes in valuation allowance		107,740		137,518
Total	$	—	$	—

Tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred liabilities are presented below:

		February 28, 2022		February 28, 2021
Deferred tax assets:				
Net operating loss carryforwards	$	5,670,900	$	5,587,416
Oil and gas properties		87,694		63,438
Stock based compensation		66,187		66,187
Other		27,838		27,838
Less valuation allowance		(5,852,619)		(5,744,879)
Total	$	—	$	—

At February 28, 2022, the Company had a net operating loss ("NOL") carryforwards for federal and state income tax purposes of approximately $19,035,827, which will begin to expire, if unused, beginning in 2024. Under the Tax Cuts and Jobs Act, the NOL portion of the loss incurred in the 2018, 2020 and 2021 period of $340,749, $339,299 and $416,898, respectively, and the loss incurred for the year ended February 28, 2022 in the amount of $311,241 will not expire and will carry over indefinitely. The valuation allowance increased approximately $107,740 for the year ended February 28, 2022 and increased approximately $137,518 for the year ended February 28, 2021. Section 382 Rule of the Internal Revenue Code will place annual limitations on the Company's NOL carryforward.

The above estimates are based upon management's decisions concerning certain elections that could change the relationship between net income and taxable income. Management decisions are made annually and could cause the estimates to vary significantly. The Company's files federal income tax returns with the United States Internal Revenue Service and state income tax returns in various state tax jurisdictions. As a general rule, the Company's tax returns for the fiscal years after 2016 currently remain subject to examinations by appropriate tax authorities. None of our tax returns are under examination at this time.

NOTE 15 — COMMITMENTS AND CONTINGENCIES:

Various lawsuits, claims and other contingencies arise in the ordinary course of the Company's business activities. While the ultimate outcome of the aforementioned contingencies are not determinable at this time, management believes that any liability or loss resulting therefrom will not materially affect the financial position, results of operations or cash flows of the Company.

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution cleanup resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage that is customary in the industry, although the Company is not fully insured against all environmental risks.

The Company is not aware of any environmental claims existing as of February 28, 2022. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental issues will not be discovered on the Company's oil and gas properties.

NOTE 16 — SUBSEQUENT EVENTS:

Short-term Convertible Note Payable

During the twelve months ended February 28, 2022, the Company executed a convertible promissory note with a third party for $200,000. On May 5, 2022, the Company received notice from the third party of their intent to convert the note principal and interest in the amount of $236,000 at the conversion price of $0.0085. Consequently, 27,764,706 shares of the Company's common stock has been issued to the third party to satisfy the obligation.

Results of Special Shareholders Meeting

At a special meeting of shareholders held on May 20, 2022, Daybreak shareholders approved the Equity Exchange Agreement between Daybreak, Reabold California, LLC ("Reabold") and Gaelic Resources, Ltd. ("Gaelic"). As a result of this approval, the Company proceeded with the acquisition of Reabold and its producing crude oil and natural gas properties in California. The acquisition was completed by Daybreak issuing 160,964,489 common stock shares to Gaelic, and in accordance with the customary closing terms and conditions for acquisitions of this nature.

At the same meeting shareholders adopted the Second and Amended Articles of Incorporation, including increasing the authorized number of common stock shares from 200,000,000 to 500,000,000 common stock shares. The increase in common stock shares will give the Company enough authorized common stock shares to complete the transaction with Reabold and Gaelic. Also, the Series A Preferred stock classification has been eliminated, since all Series A Preferred stock has previously been converted to the Company's common stock.

In conjunction with the Company's efforts to acquire Reabold, and as a condition of closing the acquisition, the Company was to secure a capital raise of $2,500,000 through the issuance of shares of the Company's common stock. That commitment for that capital raise was executed on May 5, 2022, and subsequently 128,125,000 shares were issued. The finalization of the raise, was conditional upon receiving shareholder approval of the Reabold acquisition.

Additionally, in a majority vote by shareholders a fourth person - Mr. Darren Williams, a nominee of Reabold, was added to the Board of Directors as of the date of the closing of the exchange agreement, May 25, 2022.

NOTE 17 — SUPPLEMENTARY INFORMATION FOR CRUDE OIL PRODUCING ACTIVITIES (UNAUDITED)

Capitalized Costs Relating to Crude Oil and Natural Gas Producing Activities

	As of February 28, 2022	As of February 28, 2021
Proved leasehold costs		
Mineral Interests	$ 115,119	$ 115,119
Wells, equipment and facilities	3,651,122	3,633,418
Total Proved Properties	3,766,241	3,748,537
Unproved properties		
Mineral Interests	—	55,978
Uncompleted wells, equipment and facilities	—	—
Total unproved properties	—	55,978
Less accumulated depreciation, depletion amortization and impairment	(3,230,209)	(3,192,081)
Net capitalized costs	$ 536,032	$ 612,434

Costs Incurred in Oil and Gas Producing Activities

	12 Months Ended February 28, 2022	12 Months Ended February 28, 2021
Acquisition of proved properties	$ —	$ —
Acquisition of unproved properties	—	—
Development costs	6,773	11,871
Exploration costs	—	—
Total costs incurred	$ 6,773	$ 11,871

Results of Operations from Oil and Gas Producing Activities

	12 Months Ended February 28, 2022	12 Months Ended February 28, 2021
Oil and gas revenues	$ 680,107	$ 404,901
Production costs	(231,275)	(187,858)
Exploration expenses	(56,213)	(83)
Depletion, depreciation and amortization	(49,590)	(60,063)
Impairment of oil properties	—	—
Result of oil and gas producing operations before income taxes	343,029	156,897
Provision for income taxes	—	—
Results of oil and gas producing activities	$ 343,029	$ 156,897

Proved Reserves

The Company's proved oil and natural gas reserves have been estimated by the certified independent engineering firm, PGH Petroleum and Environmental Engineers, LLC. Proved reserves are the estimated quantities 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 reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods when the estimates were made. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history; acquisitions of oil and natural gas properties; and changes in economic factors.

As of February 28, 2022, our total reserves were comprised of our working interest in East Slopes Project located in Kern County, California.

Our proved reserves are summarized in the table below:

	Oil (Barrels)	Natural Gas (Mcf)	BOE (Barrels)
Proved reserves:			
February 29, 2020	495,977	—	495,977
Revisions[1]	(50,784)	—	(50,784)
Discoveries and extensions	—	—	—
Production	(10,970)	—	(10,970)
February 28, 2021	434,223	—	434,223
Revisions[2]	3,052	—	3,052
Discoveries and extensions	89,493	—	89,493
Production	(9,613)	—	(9,613)
February 28, 2022	517,155	—	517,155

(1) The revisions of previous estimates resulted from a decrease in the estimated economic life of the reservoirs due to lower realized crude oil prices in the energy markets.
(2) The revisions of previous estimates resulted from higher realized crude oil prices in the energy markets.
(3) The discoveries and extensions resulted from additional PUD located being added due to higher oil prices in the energy markets.

The Company's proved reserves are set forth in the table below.

	Developed		Undeveloped		Total Reserves	
	Oil (Bbls)	BOE (Bbls)	Oil (Bbls)	BOE (Bbls)	Oil (Bbls)	BOE (Bbls)
February 29, 2020	113,779	113,779	382,198	382,198	495,977	495,977
February 28, 2021	95,120	95,120	339,103	339,103	434,223	434,223
February 28, 2022	117,844	117,844	399,311	399,311	517,155	517,155

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

The following information is based on the Company's best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows as of February 28, 2022 and February 28, 2021 in accordance with ASC 932, "Extractive Activities – Oil and Gas" which requires the use of a 10% discount rate. This information is not the fair market value, nor does it represent the expected present value of future cash flows of the Company's proved oil and gas reserves.

Future cash inflows for the years ended February 28, 2022 and February 28, 2021 were estimated as specified by the SEC through calculation of an average price based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period from March through February during each respective fiscal year. The resulting net cash flow are reduced to present value by applying a 10% discount factor.

	12 Months Ended	
	February 28, 2022	February 28, 2021
Future cash inflows	$ 35,580,251	$ 15,692,834
Future production costs[1]	(16,217,379)	(8,076,769)
Future development costs	(3,603,561)	(2,510,625)
Future income tax expenses[2]	—	—
Future net cash flows	15,759,311	5,105,440
10% annual discount for estimated timing of cash flows	(9,567,367)	(3,457,022)
Standardized measure of discounted future net cash flows at the end of the fiscal year	$ 6,191,944	$ 1,648,418

(1) Production costs include crude oil and natural gas operations expense, production ad valorem taxes, transportation costs and G&A expense supporting the Company's crude oil and natural gas operations.
(2) The Company has sufficient tax deductions and allowances related to proved crude oil and natural gas reserves to offset future net revenues.

Average hydrocarbon prices are set forth in the table below.

	Average Price Crude Oil (Bbl)	Natural Gas (Mcf)
Year ended February 29, 2020[1]	$ 60.25	$ —
Year ended February 28, 2021[1]	$ 36.91	$ —
Year ended February 28, 2022[1]	$ 70.75	$ —

(1) Average prices were based on 12-month unweighted arithmetic average of the first-day-of-the-month prices for the period from March through February during each respective fiscal year.

Future production and development costs, which include dismantlement and restoration expense, are computed by estimating the expenditures to be incurred in developing and producing the Company's proved crude oil and natural gas reserves at the end of the year, based on year-end costs, and assuming continuation of existing economic conditions.

Sources of Changes in Discounted Future Net Cash Flows

Principal changes in the aggregate standardized measure of discounted future net cash flows attributable to the Company's proved crude oil and natural gas reserves, as required by ASC 932, at fiscal year-end are set forth in the table below.

	12 Months Ended	
	February 28, 2022	February 28, 2021
Standardized measure of discounted future net cash flows at the beginning of the year	$ 1,648,418	$ 4,652,142
Extensions, discoveries and improved recovery, less related costs	906,390	—
Revisions of previous quantity estimates	44,898	(287,596)
Net changes in prices and production costs	3,320,241	(1,899,026)
Accretion of discount	164,842	465,214
Sales of oil produced, net of production costs	(448,832)	(217,043)
Changes in future development costs	(267,335)	(9,077)
Changes in timing of future production	823,322	(1,074,350)
Net changes in income taxes	—	—
Standardized measure of discounted future net cash flows at the end of the year	$ 6,191,944	$ 1,648,418

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Evaluation of Disclosure Controls and Procedures

As of the end of the reporting period, February 28, 2022, an evaluation was conducted by Daybreak's management, including our President and Chief Executive Officer, also serving as our interim principal finance and accounting officer, as to the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(e) of the Exchange Act. Such disclosure controls and procedures are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods specified by the SEC rules and forms. Additionally, it is vital that such information is accumulated and communicated to our management including our President and Chief Executive Officer, in a manner to allow timely decisions regarding required disclosures. Based on that evaluation, our management concluded that our disclosure controls were effective as of February 28, 2022.

Internal Control Over Financial Reporting

The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Our internal controls over financial reporting include those policies and procedures that:

1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made in accordance with authorizations of management and our Board of Directors; and
3) provide reasonable assurance regarding prevention or timely detection of any unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements.

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

Management's Report on Internal Control Over Financial Reporting

Daybreak's management, including our President and Chief Executive Officer, also serving as our interim principal finance and accounting officer is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our management assessed the effectiveness of our internal control over financial reporting as of February 28, 2022. In making this assessment, management used certain criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013).* Based on such assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of February 28, 2022.

This annual report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to SEC rules that permit the company to provide only management's report in this annual report.

Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the quarter ended February 28, 2022 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Limitations

Our management does not expect that our disclosure controls or internal controls over financial reporting will prevent all errors or all instances of fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs.

Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Controls can also be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and any design may not succeed in achieving its stated goals under all potential future conditions.

Over time, controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with policies or procedures. Because of the inherent limitation of a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable.

PART III

Certain information required by Part III is omitted from this Annual Report on Form 10-K because we will file a definitive proxy statement pursuant to Regulation 14A (the "Proxy Statement"), not later than 120 days after the end of the fiscal year covered by this Form 10-K, and certain information to be included therein is incorporated herein by reference.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Information regarding our Ethical Business Conduct Policy Statement and the Code of Ethics for Senior Financial Officers is described in the introductory pages of this Annual Report under the caption "Website / Available Information." The information required by Item 10 that relates to our directors and executive officers is incorporated by reference from the information appearing under the captions "Proposal Number 1: Election of Directors," "Executive Officers," "Corporate Governance," "Section 16(a) Beneficial Ownership Reporting Compliance" and "Report of the Audit Committee of the Board of Directors" in our Proxy Statement.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 that relates to compensation of our principal executive officers and our directors is incorporated by reference from the information appearing under the captions "Executive Compensation", "Director Compensation", "Compensation Committee Report" and "Compensation Committee Interlocks and Insider Participation" in our Proxy Statement.

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

The information required by Item 12 that relates to the ownership of securities by management and others is incorporated by reference from the information appearing under the caption "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement.

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

The information required by Item 13 that relates to business relationships and transactions with our management and other related parties is incorporated by reference from the information appearing under the captions "Corporate Governance", "Board Leadership, Structure and Risk Oversight" and "Transactions Between the Company and Management" in our Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by Item 14 that relates to services provided by our registered public accounting firm and the fees incurred for services provided during fiscal years 2022 and 2021 is incorporated by reference from the information appearing under the caption "Fees Billed by Independent Public Accountants" in our Proxy Statement.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

The following Exhibits are filed as part of the report:

2.1	Equity Exchange Agreement dated October 20, 2021 by and between Daybreak Oil and Gas, Inc., Reabold California LLC, and Gaelic Resources Ltd. (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K dated October 26, 2021, and filed on October 27, 2021).
2.2+	Letter Agreement by and between Daybreak Oil and Gas, Inc., and Gaelic Resources Ltd., effective as of February 14, 2022; to amend the Equity Exchange Agreement dated October 20, 2021 by and between Daybreak Oil and Gas, Inc., Reabold California LLC, and Gaelic Resources Ltd.
2.3+	Letter Agreement by and between Daybreak Oil and Gas, Inc., and Gaelic Resources Ltd., effective as of May 24, 2022; to amend the Equity Exchange Agreement dated October 20, 2021 and amended on February 22, 2022 by and between Daybreak Oil and Gas, Inc., Reabold California LLC, and Gaelic Resources Ltd.
3.02	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K filed on April 9, 2008).
4.01	Specimen Stock Certificate (incorporated by reference to Exhibit 4.02 of the Company's Annual Report on Form 10-K for year ended February 28, 2019)
4.02	Description of Securities (incorporated by reference to Exhibit 4.02 of the Company's Annual Report on Form 10-K for year ended February 28, 2019).
4.03	Designations of Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 of the Company's Form SB-2 on July 18, 2006, and incorporated by reference herein. (filed as part of the Articles of Amendment to the Articles of Incorporation of Daybreak Oil and Gas, Inc. dated June 30, 2006.))
4.04	Form of 12% Subordinated Note due 2015 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K, filed on February 3, 2010).
4.05	Form of Warrant in connection with 12% Subordinated Notes (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K, filed on February 3, 2010).
4.06	Form of Amendment to 12% Subordinated Note due 2015 and Warrant to Purchase Shares of Common Stock (incorporated by reference to Exhibit 4.13 of the Company's Annual Report on Form 10-K for year ended February 28, 2015).
4.07	Form of Second Amendment to 12% Subordinated Note due 2017 and Warrant to Purchase Shares of Common Stock (incorporated by reference to Exhibit 4.14 of the Company's Annual Report on Form 10-K filed on May 30, 2017).
4.08	Warrant Agreement by and between Daybreak Oil and Gas, Inc., and Bear to Bull Investor Relations, LLC, dated November 27, 2019. (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2019).
10.01	Prospect review and non-competition agreement for California project (incorporated by reference to Exhibit 10vi of the Company's SB-2/A filed on December 28, 2006).
10.02	Prospect review agreement for California project (incorporated by reference to Exhibit 10x of the Company's SB-2/A filed on December 28, 2006).

10.03 Form of Subscription Agreement for 12% Subordinated Note due 2015 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on February 3, 2010).

10.04 Promissory Note, dated June 20, 2011, by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended August 31, 2011).

10.05 Promissory Note, dated January 31, 2012, by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland (incorporated by reference to Exhibit 10.6 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2012).

10.06 Credit Line Agreement, dated October 24, 2011, by and between Daybreak Oil and Gas, Inc. and UBS Bank USA (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the quarter ended November 30, 2011).

10.07 Mortgage, Deed of Trust, Assignment of Production, Security Agreement and Financing Statement (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2020).

10.11 Promissory Note, dated August 21, 2012, by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland (incorporated by reference to Exhibit 10.7 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2012).

10.12 Promissory Note, dated December 22, 2020, by and between Daybreak Oil and Gas, Inc. and James Forrest Westmoreland and Angela Marie Westmoreland, Co-Trustees of the James and Angela Westmoreland Revocable Trust (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2020).

10.30 Securities Purchase Agreement dated December 27, 2018 by and between Daybreak Oil and Gas, Inc. and Maximilian Resources, LLC. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on January 3, 2019).

10.31 Production Payment Interest Purchase Agreement dated December 27, 2018 by and among Daybreak Oil and Gas, Inc. and the purchasers named therein. (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed on January 3, 2019).

10.32 Consulting Agreement by and between Daybreak Oil and Gas, Inc., and Bear to Bull Investor Relations, LLC, dated October 8, 2019. (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended August 31, 2019).

10.33 Form of Convertible Note Purchase Agreement and Note, issued by the Company by and between Daybreak Oil and Gas, Inc. and James F. Westmoreland dated as of January 14, 2020. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed on January 17, 2020).

10.34 Form of letter agreement regarding conversion of accrued director fees (incorporated by reference to Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2021, filed on January 18, 2022).

10.35 Form of letter agreement regarding conversion of accrued salary (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2021, filed on January 18, 2022).

10.36 Form of letter agreement dated December 3. 2021 by and between Daybreak Oil and Gas, Inc., and James F. Westmoreland regarding conversion of 12% subordinated note (incorporated by reference to Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended November 30, 2021, filed on January 18, 2022).

10. 37+	Letter agreement by and between Daybreak Oil and Gas, Inc., and James F. Westmoreland regarding conversion of Production Payment Interests
10.38+	Form of letter agreement regarding conversion of the Company's Series A Preferred shares to convert each Series A Preferred share to three (3) shares of Daybreak's common stock.
10.39+	Form of letter agreement regarding conversion of accrued and unpaid dividends with respect to the Series A Preferred Stock (the "Series A Conversion").
10.40+	Convertible Note Purchase Agreement by and between Daybreak Oil and Gas, Inc. and the purchaser dated as of February 15, 2022
23.1+	Consent of PGH Petroleum and Environmental Engineers, LLC
31.1+	Certification of principal executive and principal financial officer as required pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1+	Certification of principal executive and principal financial officer as required pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1+	Reserve Report of PGH Petroleum and Environmental Engineers, LLC, independent petroleum engineering consulting firm, as of February 28, 2021
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.*
101.XSD	Inline XBRL Taxonomy Extension Schema Document*
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document*
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document*
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document*
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document*
104	Cover Page Interactive Data File - formatted in Inline XBRL and contained in Exhibit 101

+ Filed herewith.

* Furnished herewith.

ITEM 16. FORM 10–K SUMMARY

The Company has elected not to include the optional summary information hyperlink.

SIGNATURES

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

DAYBREAK OIL AND GAS, INC.

By: /s/ JAMES F. WESTMORELAND
James F. Westmoreland, its
President, Chief Executive Officer and
interim principal finance and
accounting officer
Date: June 15, 2022

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

By: /s/ JAMES F. WESTMORELAND
James F. Westmoreland
Director / President and Chief Executive Officer
Date: June 15, 2022

By: /s/ TIMOTHY R. LINDSEY
Timothy R. Lindsey
Director
Date: June 15, 2022

By: /s/ JAMES F. MEARA
James F. Meara
Director
Date: June 15, 2022

GLOSSARY OF TERMS

The following are abbreviations and definitions of terms commonly used in the crude oil and natural gas industry and this Form 10-K.

3-D seismic. An advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

API. American Petroleum Institute, a petroleum induction association that sets standards for oil field equipment and operations. Also see Oil Gravity.

BOE. A barrel of crude oil equivalent (BOE) is the standard convention used to express crude oil and natural gas volumes on a comparable crude oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil or natural gas liquid.

Bbl. One barrel, or 42 U.S. gallons of liquid volume.

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

DD&A. Refers to depreciation, depletion and amortization of the Company's property and equipment.

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

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

Fracturing. A procedure undertaken to attempt to increase the flow of crude oil or natural gas from a well. A fluid (usually crude oil, diesel oil or water) is pumped into the reservoir with such great force that the reservoir rock is physically broken and split open. Usually the "frac fluid" carries small pellets or beads mixed in with it; the idea is for them to get caught in the fractures and prop them open (the beads or pellets are called the propping agent or proppant). As the pumping pressures are gradually released at the surface, the natural reservoir pressures will force the "frac fluid" out of the reservoir, and back into the well as the well begins to flow. The proppant remains behind, holding the fractures open, thereby increasing the flow of crude oil or natural gas from the reservoir into the well. This procedure is also called hydraulic fracturing. To "frac a well" means to hydraulically fracture a reservoir in a well.

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

Gas. Refers to natural gas. A mixture of gaseous hydrocarbons formed naturally in the earth.

Gross acres or wells. Refers to the total acres or wells in which the Company has a working interest.

Horizontal drilling. A drilling technique that permits the operator to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Hydrocarbons. A large class of organic compounds composed of hydrogen and carbon. Crude oil, natural gas and natural gas condensate are all mixtures of various hydrocarbons, among which methane is the simplest.

Hydraulic fracturing. Refer to the definition of fracturing.

Net acres or wells. Refers to the gross sum of fractional working interest ownership in gross acres or wells.

Net production. Crude oil and natural gas production that is owned by the Company, less royalties and production due others.

NYMEX. New York Mercantile Exchange, the exchange on which commodities, including crude oil and natural gas futures contracts, are traded.

Oil. Refers to crude oil or condensate. A naturally occurring mixture of liquid hydrocarbons as it comes out of the ground.

Oil Gravity. The density of liquid hydrocarbons generally measured in degrees API. The lighter the crude oil, the higher the API gravity. Heavy oil has an API gravity of 20° API or less. For example, motor lubricating oil is around 26° API; while gasoline is approximately 55° API.

Operator. The individual or company responsible for the exploration, development and production of a crude oil or natural gas well or lease.

Productive wells. Producing wells and wells mechanically capable of production.

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 means not involving a well.

Proved reserves. Proved crude oil and natural gas reserves are those quantities of crude oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. (i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible crude oil or natural gas on the basis of available geoscience and engineering data. (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. (iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved crude oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including government entities.

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

Royalty. An interest in a crude oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

SEC. The United States Securities and Exchange Commission.

Standardized measure of discounted future net cash flows. Present value of proved reserves, as adjusted to give effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, and (ii) estimated future income taxes.

Undeveloped acreage. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil or natural gas, regardless of whether such acreage contains proved reserves.

Working interest. An interest in a crude oil and natural gas lease that gives the owner of the interest the right to drill for and produce crude oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest is entitled will be smaller than the share of costs that the working interest owner is required to bear to the extent of any royalty burden.

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

Exhibit 31.1

Certification

I, James F. Westmoreland, certify that:

(1) I have reviewed this annual report on Form 10-K of Daybreak Oil and Gas, Inc.

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

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

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

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

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

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

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

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

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

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

Date: June 15, 2022

By /s/ JAMES F. WESTMORELAND
James F. Westmoreland, President, Chief Executive Officer
and interim principal finance and accounting officer
(Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Daybreak Oil and Gas, Inc. on Form 10-K for the period ending February 28, 2022, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, the undersigned, in the capacity and on the date indicated below, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: June 15, 2022

By /s/ JAMES F. WESTMORELAND
James F. Westmoreland, President, Chief Executive Officer
and interim principal finance and accounting officer
(Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer)