MEXCO ENERGY CORP
Form 10-K
June 29, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended March 31, 2016

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

Commission File No. 0-6694

MEXCO ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Colorado	**84-0627918**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

214 W. Texas Avenue, Suite 1101	
Midland, Texas	**79701**
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code: **(432) 682-1119**

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

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, $0.50 par value per share**

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

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

Indicate by check-mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve (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 ninety (90) days. Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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 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 [X]

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

The aggregate market value of the voting stock held by non-affiliates of the Registrant as of September 30, 2015 (the last business day of the Registrant’s most recently completed second quarter) was $2,228,639 based on Mexco Energy Corporation’s closing common stock price of $2.50 per share on that date as reported by the NYSE MKT.

There were 2,037,266 shares of the registrant’s common stock outstanding as of June 23, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant’s Proxy Statement relating to the 2016 Annual Meeting of Shareholders to be held on September 13, 2016, have been incorporated by reference in Part III of this Form 10-K. Such Proxy Statement will be filed with the Commission not later than 120 days after March 31, 2016, the end of the fiscal year covered by this report.

TABLE OF CONTENTS

As used in this document, “the Company”, “Mexco”, “we”, “us” and “our” refer to Mexco Energy Corporation and its consolidated subsidiaries.

Abbreviations or definitions of certain terms commonly used in the oil and gas industry and in this Form 10-K can be found in the “Glossary of Abbreviations and Terms”.

PART I

CAUTIONARY NOTE REGARDING 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, as amended, (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934, as amended, (the “Exchange Act”). These forward-looking statements are generally located in the material set forth under the headings “Risk Factors”, “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, “Business”, “Properties” but may be found in other locations as well, and are typically identified by the words “could”, “should”, “expect”, “project”, “estimate”, “believe”, “anticipate”, “intend”, “budget”, “plan”, “forecast”, “predict” and other si expressions.

Forward-looking statements generally relate to our profitability; planned capital expenditures; estimates of oil and gas production; future project dates; estimates of future oil and gas prices; estimates of oil and gas reserves; our future financial condition or results of operations; and our business strategy and other plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. Actual results in future periods may differ materially from those expressed or implied by such forward-looking statements because of a number of risks and uncertainties affecting our business, including those discussed in “Risk Factors”. The factors that may affect our expectations regarding our operations include, among others, the following: our success in development, exploitation and exploration activities; our ability to make planned capital expenditures; declines in our production or prices of oil and gas; our ability to raise equity capital or incur additional indebtedness; our restrictive debt covenants; our acquisition and divestiture activities; weather conditions and events; the proximity, capacity, cost and availability of pipelines and other transportation facilities; increases in the cost of drilling, completion and gas gathering or other costs of production and operations; and other factors discussed elsewhere in this document.

We disclaim any intention or obligation to update or revise any forward-looking statements as a result of new information, future events or otherwise.

ITEM 1. BUSINESS

General

Mexco Energy Corporation, a Colorado corporation, is an independent oil and gas company engaged in the exploration, development and production of natural gas and crude oil properties located in the United States. Incorporated in April 1972 under the name Miller Oil Company, the Company changed its name to Mexco Energy Corporation effective April 30, 1980. At that time, the shareholders of the Company also approved amendments to the Articles of Incorporation resulting in a one-for-fifty reverse stock split of the Company's common stock.

Our total estimated proved reserves at March 31, 2016 were approximately 2.051 million barrels of oil equivalent ("Boe") of which 53% was oil and natural gas liquids and 47% was natural gas, and our estimated present value of proved reserves was approximately $16 million based on estimated future net revenues excluding taxes discounted at 10% per annum, pricing and other assumptions set forth in "Item 2 – Properties" below. During fiscal 2016, we added proved reserves of 590,000 Boe through extensions and discoveries, subtracted 4,500 Boe through sales of oil and gas properties and had downward revisions of previous estimates of 136,000 Boe. Such revisions are a result of Security Exchange Commission ("SEC") rules which require such reserves to be developed within five years as well as decreased oil and natural gas prices.

Nicholas C. Taylor beneficially owns approximately 45% of the outstanding shares of our common stock. Mr. Taylor is also our Chairman of the Board and Chief Executive Officer. As a result, Mr. Taylor has significant influence in matters voted on by our shareholders, including the election of our Board members. Mr. Taylor participates in all facets of our business and has a significant impact on both our business strategy and daily operations.

Company Profile

Since our inception, we have been engaged in acquiring and developing oil and gas properties and the exploration for and production of natural gas, crude oil, condensate and natural gas liquids (“NGLs”) within the United States. We especially seek to acquire proved reserves that fit well with existing operations or in areas where Mexco has established production. Acquisitions preferably will contain most of their value in producing wells, behind pipe reserves and high quality proved undeveloped locations. Competition for the purchase of proved reserves is intense. Sellers often utilize a bid process to sell properties. This process usually intensifies the competition and makes it extremely difficult to acquire reserves without assuming significant price and production risks. We actively search for opportunities to acquire proved oil and gas properties. However, because the competition is intense, we cannot give any assurance that we will be successful in our efforts during fiscal 2017.

While we own oil and gas properties in other states, the majority of our activities are centered in the Permian Basin of West Texas. The Company also owns producing properties and undeveloped acreage in thirteen states. We acquire interests in producing and non-producing oil and gas leases from landowners and leaseholders in areas considered favorable for oil and gas exploration, development and production. In addition, we may acquire oil and gas interests by joining in oil and gas drilling prospects generated by third parties. We may also employ a combination of the above methods of obtaining producing acreage and prospects. In recent years, we have placed primary emphasis on the evaluation and purchase of producing oil and gas properties, both working and royalty interests, and prospects that could have a potentially meaningful impact on our reserves. Most of the Company’s oil and gas interests are operated by others, however the Company operates several properties in which it owns an interest.

From 1983 to 2016, Mexco Energy Corporation made approximately 80 acquisitions of producing oil and gas properties including royalties, overriding royalties, minerals and working interests both operated and non-operated plus the following most significant and recent acquisitions:

1993-2010	Tabbs Bay Oil Company and Thompson Brothers Lumber Company, respectively dissolved in 1957 and 1947. Purchase covering thousands of acres located respectively in 19 counties of Texas, 3 parishes of Louisiana and one county in Arkansas and 8 counties of Texas, respectively consisting of various mineral, royalty and overriding royalty interests.
1997	Forman Energy Corporation, purchase price of $1,591,000 consisting of primarily working interests in approximately 634 wells located in 12 states.
2010	Southwest Texas Disposal Corporation, purchase price $478,000 consisting of royalty interests in over 300 wells located in 60 counties and parishes of 6 states.
2012	TBO Oil and Gas, LLC, purchase price of $1,150,000 consisting of working interests in approximately 280 wells located in 16 counties of 3 states.

2014 Royalty interests, purchase price of $200,000 covering 43 wells in 12 counties of eight states. Of these oil and gas reserves, approximately 54% are in TX and 10% in LA.

Royalty interests, purchase price $580,000 covering 580 wells in 87 counties of eight states. Approximately 90% of the net revenue from these royalties is produced by 157 wells located in the Barnett Shale of the Fort Worth Basin of Texas. Also included are interests in 423 wells in 8 states.

Non-Operated working interests, purchase price $525,000 for 12.5% (approximately 10% net revenue interest). Eight wells now producing oil on 20-acre spacing at approximately 3,600 foot depth on the 190 acres in Pecos County, TX. The operator has agreed to pay all operating expenses of these interests. Mexco also receives 100% of the gross disposal fees paid by an adjacent operator for one disposal well located on these properties.

Royalty and mineral interests, purchase price $1,000,000 covering approximately 1,800 wells in 27 counties of Texas. Of these oil and gas reserves, approximately 80% is natural gas and 20% oil.

Non-Operated working interests, purchase price $840,000 in 70 Natural gas producing wells located in 5 counties of Oklahoma.

Industry Environment and Outlook

Crude oil prices remained significantly depressed in fiscal 2016 and face continued downward pressure due to domestic and global supply and demand factors. The downward price pressure intensified in late 2015 and early 2016, with crude oil prices dropping below $23 per barrel in February 2016, a level not seen since 2003. Natural gas prices faced similar downward pressure, dropping below $1.50 per mcf in March 2016.

In light of the challenges facing our industry and in response to these price declines, our primary business strategies for fiscal 2017 will include: (1) optimizing cash flows through operating efficiencies and cost reductions, (2) divesting of non-core assets, and (3) working to balance capital spending with cash flows to minimize new borrowings, reduce debt and maintain ample liquidity.

See Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations for discussion of our fiscal 2016 operating results and potential impact on fiscal 2017 operating results due to depressed commodity prices.

Oil and Gas Operations

As of March 31, 2016, oil constituted approximately 53% of our total proved reserves and approximately 67% of our revenues for fiscal 2016. Revenues from oil and gas royalty interests accounted for approximately 24% of our revenues for fiscal 2016.

Mexco believes there is potential for horizontal drilling, multi-stage fracturing and production of oil and gas in a substantial number of properties containing approximately 1,150 wells in which Mexco holds an interest. These wells are located in the core area of the horizontal Wolfcamp multi-zone formation in Reagan, Upton, Midland, Martin, Glasscock and Andrews Counties in the Midland Basin of West Texas. Such interests vary from .125% to 7.68% working interest (.094% to 6.24% net revenue interest, respectively).

In addition to these working interests, we also own various mineral and royalty interests in and around these core counties in the Midland Basin, a part of the Permian Basin of West Texas.

There are two primary areas in which the Company is focused, 1) the Midland Basin located in the Eastern portion of the Permian Basin including Reagan, Upton, Midland, Martin, Howard, Glasscock and Crockett Counties, Texas and 2) the Delaware Basin located in the Western portion of the Permian Basin including Lea and Eddy Counties, New Mexico and Loving County, Texas.

The Midland Basin properties, encompassing 71,477 gross acres, 285 net acres, 534 gross producing wells and 2.5 net wells account for approximately 42% of our discounted future net cash flows from proved reserves as of March 31, 2016. Of these discounted future net cash flows from proved reserves, approximately 32% are attributable to proven undeveloped reserves which will be developed through new drilling. For fiscal 2016, these properties accounted for 19% of our gross revenues and 24% of our net revenues.

The Delaware Basin properties, encompassing 29,638 gross acres, 623 net acres, 458 gross producing wells and 5.2 net wells account for approximately 18% of our discounted future net cash flows from proved reserves as of March 31, 2016. Of these discounted future net cash flows from proved reserves, approximately 2% are attributable to proven undeveloped reserves which will be developed through new drilling. For fiscal 2016, these properties accounted for 24% of our gross revenues and 29% of our net revenues.

Gomez Gas Field properties, encompassing 13,058 gross acres, 72 net acres, 26 gross wells and .13 net wells in Pecos County, Texas, account for approximately 3% of our discounted future net cash flows from proved reserves as of March 31, 2015. For fiscal 2016, these properties accounted for 3% of our gross revenues and 5% of our net revenues. All of these properties, except for one, are royalty interests. There is a potential for development of the horizontal Wolfcamp on these interests.

The Goldsmith North Field (San Andres formation) long-lived oil producing properties, encompassing 240 gross acres, 153 net acres, 3 gross wells in Ector County, Texas, account for 7.3% of our discounted future net cash flows from proved reserves as of March 31, 2016. Of these discounted future net cash flows from proved reserves, 7% are attributable to proven undeveloped reserves which will be developed through new drilling of 4 wells. For fiscal 2016, these properties consist of working interests and accounted for 3% of our gross revenues and .1% of our net revenues.

In August 2013, Mexco assigned Pioneer Natural Resources Company a three year term leasehold interest in 417.33 net acres (837.33 gross acres) of undeveloped acreage located above and below the Pembrook Unit of Upton County, Texas and retained a 1% royalty.

In November 2015, Mexco extended a six month option for which the Company received $112,000 for a three year assignment of a leasehold interest in 320 net acres (640 gross acres) in Upton County, Texas. The purchaser paid Mexco $2,000 per acre for a total of $640,000. Mexco also retained a 1% overriding royalty interest in this acreage. This acreage has the potential for horizontal development in multiple zones of the horizontal Wolfcamp formation centered in the southern Midland Basin. The purchaser advises that he has obtained rights to explore the balance of the undivided 640 acres from Apache Corporation and has been advised that Parsley Energy, Inc. plans to develop this property.

Mexco believes its most important properties for future development by horizontal drilling and hydraulic fracturing area located in Midland, Reagan and Upton Counties, Texas of the Midland Basin.

For more on these and other operations in this area see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources Commitments”.

We own interests in and operate 13 producing wells and 1 water injection well. We own partial interests in an additional 6,461 producing wells all of which are located within the United States in the states of Texas, New Mexico, Oklahoma, Louisiana, Alabama, Mississippi, Arkansas, Wyoming, Kansas, Colorado, Montana, Virginia and North Dakota. Additional information concerning these properties and our oil and gas reserves is provided below.

The following table indicates our oil and gas production in each of the last five years:

Year	Oil(Bbls)	Gas (Mcf)
2016	38,930	407,939

2015	29,557	369,034
2014	27,186	361,652
2013	23,260	401,077
2012	19,442	395,649

Competition and Markets

The oil and gas industry is a highly competitive business. Competition for oil and gas reserve acquisitions is significant. We may compete with major oil and gas companies, other independent oil and gas companies and individual producers and operators, some of which have financial and personnel resources substantially in excess of those available to us. As a result, we may be placed at a competitive disadvantage. Competitive factors include price, contract terms and types and quality of service, including pipeline distribution. The price for oil and gas is widely followed and is generally subject to worldwide market factors. Our ability to acquire and develop additional properties in the future will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment in a timely manner.

In addition, the oil and gas industry as a whole also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. The price and availability of alternative energy sources could adversely affect our revenue.

Market factors affect the quantities of oil and natural gas production and the price we can obtain for the production from our oil and natural gas properties. Such factors include: the extent of domestic production; the level of imports of foreign oil and natural gas; the general level of market demand on a regional, national and worldwide basis; domestic and foreign economic conditions that determine levels of industrial production; political events in foreign oil-producing regions; and variations in governmental regulations including environmental, energy conservation and tax laws or the imposition of new regulatory requirements upon the oil and natural gas industry.

The market for our oil, gas and natural gas liquids production depends on factors beyond our control including: domestic and foreign political conditions; the overall level of supply of and demand for oil, gas and natural gas liquids; the price of imports of oil and gas; weather conditions; the price and availability of alternative fuels; the proximity and capacity of gas pipelines and other transportation facilities; and overall economic conditions.

Major Customers

We made sales to the following companies that amounted to 10% or more of revenues for the year ended March 31:

	2016	2015	2014
Holly Frontier Refining & Marketing LLC	14 %	17 %	22 %
Plains Marketing LP	18 %	8 %	8 %

Because a ready market exists for oil and gas production, we do not believe the loss of any individual customer would have a material adverse effect on our financial position or results of operations.

Regulation

Our exploration, development, production and marketing operations are subject to various types of extensive rules and regulations by federal, state and local authorities. Numerous federal, state and local departments and agencies have issued rules and regulations binding on the oil and gas industry, some of which carry substantial penalties for noncompliance. State statutes and regulations require permits and bonds for drilling operations and reports concerning operations. Most states and some counties and municipalities in which we operate regulate the location of wells; the method of drilling and casing wells; the rates of production or “allowables”; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and notice to, and consultation with, surface owners and other third parties. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. Because these rules and regulations are frequently amended or reinterpreted, we are not able to predict the future cost or impact of complying with such laws.

The Federal Energy Regulatory Commission (“FERC”) regulates under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, interstate natural gas transportation rates and service conditions, which affect the marketing of natural gas we produce, as well as the revenues we receive for sales of such production. Since 1978, various laws have been enacted which have significantly altered the marketing and transportation of gas. These orders resulted in a fundamental restructuring of interstate pipeline sales and transportation services, including the unbundling by interstate pipelines of the sales, transportation, storage and other components of the city-gate sales, services such pipelines previously performed.

Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC’s initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated. Therefore, we cannot guarantee that the less stringent regulatory approach will continue indefinitely into the future, nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated market prices. Nevertheless, Congress could reenact price controls in the future. The price we receive from the sale of these products is affected by the cost of transporting the products to market. The FERC regulates interstate crude oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate crude oil pipeline rates must be cost-based, although many pipeline charges are today based on historical rates adjusted for inflation and other factors, and other charges may result from settlement rates agreed to by all shippers or market-based rates, which are permitted in certain circumstances. Intrastate crude oil pipeline transportation rates are subject to regulation by state regulatory commissions. Insofar as the interstate and intrastate transportation rates that we pay are generally applicable to all comparable shippers, we believe that the regulation of crude oil transportation rates will not affect our operations in a way that materially differs from the effect on the operations of our competitors who are similarly situated. Further, interstate and intrastate common carrier crude oil pipelines must provide service on an equitable basis. Under this standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When crude oil pipelines operate at full capacity, access is governed by prorating provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to crude oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

The State of Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both.

States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill. The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Environmental Matters

By nature of our oil and gas operations, we are subject to extensive federal, state and local environmental laws and regulations controlling the generation, use, storage and discharge of materials into the environment or otherwise relating to the protection of the environment. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or production commences; restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities; limit or prohibit construction or drilling activities on certain lands lying within protected areas; restrict the rate of oil and gas production; require remedial actions to prevent pollution from former operations; and impose substantial liabilities for pollution resulting from our operations. In addition, these laws and regulations may impose substantial liabilities and penalties for failure to comply with them or for any contamination resulting from our operations. We believe we are in compliance, in all material respects, with applicable environmental requirements. We do not believe costs relating to these laws and regulations have had a material adverse effect on our operations or financial condition in the past. Public interest in the protection of the environment has increased dramatically in recent years.

The trend of applying more expansive and stricter environmental legislation and regulations to the natural gas and oil industry could continue, resulting in increased costs of doing business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

The following are some of the existing laws, rules and regulations to which our business is subject:

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances. Under CERCLA, such persons may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We do not believe that we will be required to incur any material capital expenditures to comply with existing environmental requirements.

The federal *Clean Air Act* ("CAA"), and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of oil and gas properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas may require oil and natural gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

In addition, some oil and natural gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. On April 17, 2012, the EPA issued a final rule that established new source performance standards for volatile organic compounds, or VOCs, and sulfur dioxide, an air toxics standard for major sources of oil and natural gas production, and an air toxics standard for major sources of natural gas transmission and storage. These regulations apply to natural gas wells that are hydraulically fractured, or refractured, and to storage tanks and other equipment. Since January 1, 2015, all wells subject to the rule have been required to use "green completion" technology to limit emissions during well completion operations.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases ("GHGs") and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In September 2009, the EPA issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA.

The EPA's finding, the GHG reporting rules, and the rules to regulate the emissions of GHGs may affect the outcome of other climate change lawsuits pending in U.S. federal courts in a manner unfavorable to our industry. In addition to the EPA's actions to regulate GHGs, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of GHGs. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. Any of the climate change regulatory and legislative initiatives described above in areas in which we conduct business could result in increased compliance costs or additional operating restrictions which could have a material adverse effect on our business, financial condition, and results of operations.

The Federal Water Pollution Control Act ("Clean Water Act") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including produced waters and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the applicable state agency. Although the costs to comply with such mandates under state or federal law may be significant, the entire industry will experience similar costs, and we do not believe that these costs will have a material adverse impact on our financial condition and operations.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws govern the handling and disposal of hazardous and solid wastes. Wastes that are classified as hazardous under RCRA are subject to stringent handling, recordkeeping, disposal and reporting requirements. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, many ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing hazardous waste may be significant, we do not expect to experience more burdensome costs than similarly situated companies.

The Safe Drinking Water Act ("SDWA") and the *Underground Injection Control* ("UIC") program promulgated under the SDWA and state and local laws regulate the drilling and operation of salt water disposal ("SWD") wells and the underground injection of waste substances produced from oil and gas operations. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production. The EPA directly administers the UIC program in some states and in others it is delegated to the state for administering. Permits must be obtained before drilling SWD wells and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater into groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. We currently operate one underground injection well and own interests in various underground injection wells operated by others and failure to abide by their permits could subject us and those operators to civil and/or criminal enforcement. We are, and believe the other operators are as well, in compliance in all material respects with the requirements of applicable state underground injection control programs and permits.

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly oil and natural gas, from tight formations, including shales. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many newer wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. We engage third parties to occasionally provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells we operate. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions.

For example, the Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit after February 1, 2012. This law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

We believe that we are in compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, however we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operation. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended March 31, 2016. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during fiscal 2017.

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the *Endangered Species Act* and the *Migratory Bird Treaty Act*, as well as, the CWA and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time properties believed to be suitable for drilling operations are acquired by us. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted and curative work is performed with respect to significant defects, if any, before proceeding with operations. A thorough title examination has been performed with respect to substantially all leasehold producing properties currently owned by us. We believe the title to our leasehold properties is good and defensible in accordance with standards generally acceptable in the oil and gas industry subject to such exceptions that, in the opinion of counsel employed in the various areas in which we have conducted exploration activities, are not so material as to detract substantially from the use of such properties.

The leasehold properties we own are subject to royalty, overriding royalty and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements and current taxes, development obligations under oil and gas leases and other encumbrances, easements and restrictions. We do not believe any of these burdens will materially interfere with the use of these properties.

Substantially all of our properties are currently mortgaged under a deed of trust to secure funding through a revolving line of credit.

Insurance

Our operations are subject to all the risks inherent in the exploration for and development and production of oil and gas including blowouts, fires and other casualties. We maintain insurance coverage customary for operations of a similar nature, but losses could arise from uninsured risks or in amounts in excess of existing insurance coverage.

Executive Officers

The following table sets forth certain information concerning the executive officers of the Company as of March 31, 2016.

Name	Age	Position
Nicholas C. Taylor	78	Chairman and Chief Executive Officer
Tamala L. McComic	47	President, Chief Financial Officer, Treasurer, and Assistant Secretary
Donna Gail Yanko	71	Vice President and Secretary

12

Set forth below is a description of the principal occupations during at least the past five years of each executive officer of the Company.

Nicholas C. Taylor was elected Chairman of the Board and Chief Executive Officer of the Company in September 2011 and continues to serve in such capacity on a part time basis, as required. He served as Chief Executive Officer, President and Director of the Company from 1983 to 2011. From July 1993 to the present, Mr. Taylor has been involved in the independent practice of law and other business activities. In November 2005 he was appointed by the Speaker of the House to the Texas Ethics Commission and served until February 2010.

Tamala L. McComic, a Certified Public Accountant, became Controller for the Company in July 2001 and was elected President and Chief Financial Officer in September 2011. She served the Company as Executive Vice President and Chief Financial Officer from 2009 to 2011 and Vice President and Chief Financial Officer from 2003 to 2009. Prior thereto, Ms. McComic was appointed Treasurer and Assistant Secretary of the Company.

Donna Gail Yanko was appointed to the position of Vice President of the Company in 1990. She has also served as Corporate Secretary since 1992 and from 1986 to 1992 was Assistant Secretary. From 1986 to 2015, on a part-time basis, she has assisted the Chairman of the Board of the Company in his personal business activities. Ms. Yanko also served as a director of the Company from 1990 to 2008.

Employees

As of March 31, 2015, we had four full-time and three part-time employees. We believe that relations with these employees are generally satisfactory. From time to time, we utilize the services of independent geological, land and engineering consultants on a limited basis and expect to continue to do so in the future. We also utilize the services of independent contractors to perform well drilling and production operations, including pumping, maintenance, inspection and testing.

Office Facilities

Our principal offices are located at 214 W. Texas Avenue, Suite 1101, Midland, Texas 79701, and our telephone number is (432) 682-1119. On April 1, 2013, we agreed to a three year lease, with an option to renew for an additional two years, for our 3,199 square feet of office space which expired on April 1, 2016. On April 1, 2014, we agreed to a three year lease for an additional 340 square feet of office space which will expire on April 1, 2017. In February 2016, we exercised our option to renew the April 1, 2013 lease extending its expiration to April 1, 2018. We believe our facilities are adequate for our current operations and that we can obtain additional leased space if needed.

Access to Company Reports

Mexco Energy Corporation files annual, quarterly and current reports, proxy statements and other information with the SEC. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet website (www.sec.gov) that contains annual, quarterly and current reports, proxy statements and other information that issuers, including Mexco, file electronically with the SEC.

We also maintain an internet website at www.mexcoenergy.com. In the Investor Relations section, our website contains our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and other reports and amendments to those reports as soon as reasonably practicable after such material is electronically filed with the SEC. Information on our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC. Additionally, our Code of Business Conduct and Ethics and the charters of our Audit Committee, Compensation Committee and Nominating Committee are posted on our website. Any of these corporate documents as well as any of the SEC filed reports are available in print free of charge to any stockholder who requests them. Requests should be directed to our corporate Assistant Secretary by mail to P.O. Box 10502, Midland, Texas 79702 or by email to mexco@sbcglobal.net.

ITEM 1A. RISK FACTORS

There are many factors that affect our business and results of operations, some of which are beyond our control. The following is a description of some of the important factors that could have a material adverse effect on our business, financial position, liquidity and results of operations. Some of the following risks relate principally to the industry in which we operate and to our business. Other risks relate principally to the securities markets and ownership of our common stock.

RISKS RELATED TO OUR BUSINESS AND INDUSTRY

Volatility of oil and gas prices significantly affects our results and profitability.

Prices for oil and natural gas fluctuate widely. We cannot predict future oil and natural gas prices with any certainty. Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile. Factors that can cause price fluctuations include the level of global demand for petroleum products; foreign supply and pricing of oil and gas; the ability of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain oil price and production controls; nature and extent of governmental regulation and taxation, including environmental regulations; level of domestic and international exploration, drilling and production activity; the cost of exploring for, producing and delivering oil and gas; speculative trading in crude oil and natural gas derivative contracts; availability, proximity and capacity of oil and gas pipelines and other transportation facilities; weather conditions; the price and availability of alternative fuels; technological advances affecting energy consumption; and, overall political and economic conditions in oil producing countries.

Increases and decreases in prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow from banks may be subject to redetermination based on changes in prices. In addition, we may have ceiling test writedowns when prices decline. Lower prices may also reduce the amount of crude oil and natural gas that can be produced economically. Thus, we may experience material increases or decreases in reserve quantities solely as a result of price changes and not as a result of drilling or well performance.

Changes in oil and gas prices impact both estimated future net revenue and the estimated quantity of proved reserves. Any reduction in reserves, including reductions due to price fluctuations, can reduce the borrowing base under our revolving credit facility and adversely affect the amount of cash flow available for capital expenditures and our ability to obtain additional capital for our exploration and development activities.

Oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Our financial results are more sensitive to movements in natural gas prices than oil prices because most of our production is natural gas. Lower prices or lack of storage may have an adverse affect on our financial condition due to reduction of our revenues, operating income and cash flows; curtailment or shut-in of our production due to lack of transportation or storage capacity; cause certain properties in our portfolio to become economically unviable; and, limit our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations.

Lower oil and gas prices and other factors may cause us to record ceiling test writedowns.

Lower oil and gas prices increase the risk of ceiling limitation write-downs. We use the full cost method to account for oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop crude oil and natural gas properties. Under the full cost accounting rules, the net capitalized cost of crude oil and natural gas properties may not exceed a “ceiling limit” which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10% plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess against earnings. This is called a “ceiling test writedown.” Under the accounting rules, we are required to perform a ceiling test each quarter. A ceiling test writedown does not impact cash flow from operating activities, but does reduce stockholders’ equity and earnings. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when oil and natural gas prices are low. We incurred impairment charges during fiscal 2016 and may incur additional impairment charges in the future, particularly if commodity prices remain at their currently low levels or decline further, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. There were no ceiling test impairments on our oil and gas properties during fiscal 2015 and 2014.

In the past we have entered into price swap derivatives and may in the future enter into additional price swap derivatives for a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil.

We have used price swap derivatives to reduce price volatility associated with certain of our oil sales. Under these swap contracts, we receive a fixed price per barrel of oil and pay a floating market price per barrel of oil to the counterparty based on NYMEX WTI pricing. The fixed-price payment and the floating-price payment are offset, resulting in a net amount due to or from the counterparty. Such contracts and any future swap arrangements may expose us to risk of financial loss in certain circumstances, including instances where production is less than expected or oil prices increase. In addition, these arrangements may limit the benefit to us of increases in the price of oil.

We must replace reserves we produce.

Our future success depends upon our ability to find, develop or acquire additional, economically recoverable oil and gas reserves. Our proved reserves will generally decline as reserves are depleted, except to the extent that we can find, develop or acquire replacement reserves. One offset to the obvious benefits afforded by higher product prices especially for small to mid-cap companies in this industry, is that quality domestic oil and gas reserves are hard to find.

Approximately 47% and 39% of our total estimated net proved reserves at March 31, 2016 and 2015, respectively, were undeveloped, and those reserves may not ultimately be developed.

Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. If we or the outside operators of our properties choose not to spend the capital to develop these reserves, or if we are not able to successfully develop these reserves, we will be required to write-off these reserves. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our common stock.

Information concerning our reserves and future net revenues estimates is inherently uncertain.

Estimates of oil and gas reserves, by necessity, are projections based on engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, such as future production, oil and gas prices, operating costs, development costs and remedial costs, all of which may vary considerably from actual results. As a result, estimates of the economically recoverable quantities of oil and gas and of future net cash flows expected therefrom may vary substantially. As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on a twelve month un-weighted first-day-of-the-month average oil and gas prices for the twelve months prior to the date of the report. Actual future prices and costs may be materially higher or lower.

An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations.

Our oil and gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for our oil and gas are typically lower than the relevant benchmark prices, such as The New York Mercantile Exchange (“NYMEX”). The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Additionally, insufficient pipeline capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas. During fiscal 2016, differentials averaged $1.01 per Bbl of oil and $0.39 per Mcf of gas. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

Our exploration and development drilling may not result in commercially productive reserves.

New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that crude oil or natural gas is present or may be produced economically. Drilling for crude oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Drilling and operating activities are high risk activities that subject us to a variety of factors that we cannot control.

These factors include availability of workover and drilling rigs, well blowouts, cratering, explosions, fires, formations with abnormal pressures, pollution, releases of toxic gases and other environmental hazards and risks. Any of these operating hazards could result in substantial losses to us. In addition, we incur the risk that no commercially productive reservoirs will be encountered, and there is no assurance that we will recover all or any portion of our investment in wells drilled or re-entered.

Acquisitions are subject to the risks and uncertainties of evaluating reserves and potential liabilities and may be disruptive and difficult to integrate into our business.

We plan to continue growing our reserves through acquisitions. Acquired properties can be subject to significant unknown liabilities. Prior to completing an acquisition, it is generally not feasible to conduct a detailed review of each individual property to be acquired in an acquisition. Even a detailed review or inspection of each property may not reveal all existing or potential liabilities associated with owning or operating the property. Moreover, some potential liabilities, such as environmental liabilities related to groundwater contamination, may not be discovered even when a review or inspection is performed. Our initial reserve estimates for acquired properties may be inaccurate. Downward adjustments to our estimated proved reserves, including reserves added through acquisitions, could require us to write down the carrying value of our oil and gas properties, which would reduce our earnings and our stockholders' equity. In addition, we may have to assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

We may not be able to fund the capital expenditures that will be required for us to increase reserves and production.

We must make capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have used our cash flow from operations and borrowings under our revolving credit facility to fund our capital expenditures, however, lower oil and gas prices may prevent these options. Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of planned capital expenditures, a greater percentage of our cash flow from operations will be required for debt service and operating expenses and our planned capital expenditures would, by necessity, be decreased.

The borrowing base under our credit facility will be determined from time to time by the lender. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under the credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/or production, inability to drill or unfavorable drilling results, changes in oil and gas reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

If cash flow from operations or our borrowing base decrease for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under the credit facility is reduced, we would be required to reduce our borrowings under the credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, we may be in default under the credit facility.

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

Our management has specifically identified and scheduled 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 crude oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations.

Failure to comply with covenants under our debt agreement could adversely impact our financial condition and results of operations.

Our revolving credit facility agreement requires us to comply with certain customary covenants including limitations on change of control, disposition of assets, mergers and reorganizations. We are also obligated to meet certain financial covenants. For example, our revolving credit facility requires, among other things, minimum earnings before interest, taxes, depreciation and amortization ("EBITDA") of $100,000 for the two fiscal quarters ending September 30, 2016, $300,000 for the three fiscal quarters ending December 31, 2016, $500,000 for the four fiscal quarters ending March 31, 2017 and $650,000 for each trailing fiscal quarter period thereafter and minimum interest coverage ratios (EBITDA/Interest Expense) of 1.25 to 1 for the fiscal quarter ending June 30, 2016 and 2 to 1 for each quarter thereafter. If we fail to meet any of these loan covenants, the lender under the revolving credit facility could accelerate the indebtedness and seek to foreclose on the pledged assets.

The oil and gas industry is highly competitive.

Competition for oil and gas reserve acquisitions is significant. We may compete with major oil and gas companies, other independent oil and gas companies and individual producers and operators, some of which have financial and personnel resources substantially in excess of those available to us. As a result, we may be placed at a competitive disadvantage. Our ability to acquire and develop additional properties in the future will depend upon our ability to select and acquire suitable producing properties and prospects for future development activities. In addition, the oil and gas industry as a whole also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. The price and availability of alternative energy sources could adversely affect our revenue. The market for our oil, gas and natural gas liquids production depends on factors beyond our control, including domestic and foreign political conditions, the overall level of supply of and demand for oil, gas and natural gas liquids, the price of imports of oil and gas, weather conditions, the price and availability of alternative fuels, the proximity and capacity of gas pipelines and other transportation facilities and overall economic conditions.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A substantial amount of our business activities are conducted through joint operating or other agreements under which we own working and royalty interests in natural gas and oil properties in which we do not operate. As a result, we have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. The failure of an operator of our wells to adequately perform operations could reduce our revenues and production.

Our business depends on oil and natural gas transportation facilities which are owned by others.

The marketability of our production depends in part on the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could all affect our ability to produce and market our oil and gas.

We may not be insured against all of the operating hazards to which our business is exposed.

Our operations are subject to all the risks inherent in the exploration for, and development and production of oil and gas including blowouts, fires and other casualties. We maintain insurance coverage customary for operations of a similar nature, but losses could arise from uninsured risks or in amounts in excess of existing insurance coverage.

Increases in taxes on energy sources may adversely affect the company's operations.

Federal, state and local governments which have jurisdiction in areas where the company operates impose taxes on the oil and natural gas products sold. Historically, there has been an on-going consideration by federal, state and local officials concerning a variety of energy tax proposals. Such matters are beyond our ability to accurately predict or control.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President's Fiscal Year 2016 Budget Proposal includes provisions that would, if enacted, make significant changes to U. S. federal income tax laws including the elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies. Other changes include, but are not limited to: (1) the repeal of the percentage depletion allowance for 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 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 or how soon any such changes could become effective. The passage of this legislation or any other similar changes in the U. S. federal income tax laws could negatively affect our financial condition and results of operations.

The loss of our chief executive officer or other key personnel could adversely impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, upon the continued services of our Chief Executive Officer, Nicholas C. Taylor, our President and Chief Financial Officer, Tamala L. McComic, and other key personnel, who have extensive experience and expertise in evaluating and analyzing producing oil and gas properties and drilling prospects, maximizing production from oil and gas properties and developing and executing acquisitions and financing. We do not have key-man insurance on the lives of Mr. Taylor and Ms. McComic. The unexpected loss of the services of one or more of these individuals could, therefore, significantly and adversely affect our operations. Competition for qualified individuals is intense and we may be unable to find or attract qualified replacements for our officers and key employees on acceptable terms.

We may be affected by one substantial shareholder.

Nicholas C. Taylor beneficially owns approximately 45% of the outstanding shares of our common stock. Mr. Taylor is also our Chairman of the Board and Chief Executive Officer. As a result, Mr. Taylor has significant influence in matters voted on by our shareholders, including the election of our Board members. Mr. Taylor participates in all facets of our business and has a significant impact on both our business strategy and daily operations. The retirement, incapacity or death of Mr. Taylor, or any change in the power to vote shares beneficially owned by Mr. Taylor, could result in negative market or industry perception and could have an adverse effect on our business.

RISKS RELATED TO OUR COMMON STOCK

We may issue additional shares of common stock in the future, which could cause dilution to all shareholders.

We may seek to raise additional equity capital in the future. Any issuance of additional shares of our common stock will dilute the percentage ownership interest of all shareholders and may dilute the book value per share of our common stock.

We have not and do not anticipate paying any cash dividends on our common stock in the foreseeable future.

We have paid no cash dividends on our common stock to date and it is not anticipated that any will be paid to holders of our common stock in the foreseeable future. The terms of our existing credit facility restricts the payment of dividends without the prior written consent of the lenders. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Stockholders 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.

Control by our executive officers and directors may limit your ability to influence the outcome of matters requiring stockholder approval and could discourage our potential acquisition by third parties.

As of March 31, 2016, our executive officers and directors beneficially owned approximately 48% of our common stock. These stockholders, if acting together, would be able to influence significantly all matters requiring approval by our stockholders, including the election of our board of directors and the approval of mergers or other business combination transactions.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Mexco common stock is traded on the NYSE MKT. The market price of our common stock has and could continue to experience volatility due to reasons unrelated to our operating performance. These reasons include: supply and demand for natural gas and oil; political conditions in natural gas and oil producing regions; demand for our common stock and limited trading volume; investor perception of our industry; fluctuations in commodity prices; variations in our results of operations; legislative or regulatory changes; general trends in the oil and natural gas industry; market conditions and analysts' estimates; and, other events in the oil and gas industry.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. We cannot assure you that the market price of our common stock will not fluctuate or decline significantly in the future. In addition, the stock markets in general can experience considerable price and volume fluctuations.

Failure of the Company's internal control over financial reporting could harm its business and financial results.

The management of Mexco is responsible for establishing and maintaining effective internal control over financial reporting. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes maintaining records that in reasonable detail accurately and fairly reflect Mexco’s transactions; providing reasonable assurance that transactions are recorded as necessary for preparation of the financial statements; providing reasonable assurance that receipts and expenditures are made in accordance with management authorization; and providing reasonable assurance that unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements would be prevented or detected on a timely basis.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties consist primarily of oil and gas wells and our ownership in leasehold acreage, both developed and undeveloped. As of March 31, 2016, we had interests in 6,461 gross (34.3 net) oil and gas wells and owned leasehold mineral and royalty interests in approximately 580,978 gross (5,152 net) acres.

Oil and Natural Gas Reserves

In accordance with current SEC rules, the average prices used in computing reserves at March 31, 2016 were $41.76 per bbl of oil and $74.84 in 2015, a decrease of 44%, and $1.998 per mcf of natural gas and $3.595 in 2015, a decrease of 44%, such prices are based on the 12-month unweighted arithmetic average market prices for sales of oil and natural gas on the first calendar day of each month during fiscal 2016. The benchmark price of $42.77 per bbl of oil at March 31, 2016 versus $79.21 at March 31, 2015, was adjusted by lease for gravity, transportation fees and regional price differentials and did not give effect to derivative transactions. The benchmark price of $2.39 per mcf of natural gas at March 31, 2016 versus $3.88 at March 31, 2015, was adjusted by lease for BTU content, transportation fees and regional price differentials. The average prices used in computing reserves at March 31, 2014 were $94.23 per bbl of oil and $3.67 per mcf of natural gas. The benchmark prices used in computing reserves at March 31, 2014 were $94.92 per bbl of oil and $3.99 per mcf of natural gas.

For information concerning our costs incurred for oil and gas operations, net revenues from oil and gas production, estimated future net revenues attributable to our oil and gas reserves, present value of future net revenues discounted at 10% and changes therein, see Notes to the Company's consolidated financial statements.

The engineering report with respect to Mexco's estimates of proved oil and gas reserves as of March 31, 2016, 2015 and 2014 is based on evaluations prepared by Joe C. Neal and Associates, Petroleum and Environmental Engineering Consultants, based in Midland, Texas ("Neal and Associates"), a summary of which is filed as Exhibit 99.1 to this annual report.

Management maintains internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations provided by the SEC. As stated above, Mexco retained Joe C. Neal and Associates to prepare estimates of our oil and gas reserves. Management works closely with this firm, and is responsible for providing accurate operating and technical data to it. Our Chief Financial Officer who has over 20 years experience in the oil and gas industry reviews the final reserves estimate and consults with a degreed geological consultant with extensive geological experience and if necessary, discusses the process used and findings with Mr. Neal. Mr. Neal is responsible for overseeing the preparation of the reserve estimates and holds a bachelor's degree in mechanical engineering (petroleum option), is a member of the Society of Petroleum Engineers and has over 50 years of experience in the oil and gas industry. Our Chairman and Chief Executive Officer who has over 40 years of experience in the oil and gas industry also reviews the final reserves estimate.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological 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 those expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production.

Numerous uncertainties exist in estimating quantities of proved reserves. Reserve estimates are imprecise and subjective and may change at any time as additional information becomes available. Furthermore, estimates of oil and gas reserves are projections based on engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from the assumptions and estimates. Any significant variance could materially affect the estimated quantities and value of our oil and gas reserves, which in turn may adversely affect our cash flow, results of operations and the availability of capital resources.

Per the current SEC rules, the prices used to calculate our proved reserves and the present value of proved reserves set forth herein are made using the 12-month unweighted arithmetic average of the first-day-of-the-month price. All prices are held constant throughout the life of the properties. Actual future prices and costs may be materially higher or lower than those as of the date of the estimate. The timing of both the production and the expenses with respect to the development and production of oil and gas properties will affect the timing of future net cash flows from proved reserves and their present value. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

Our estimated proved oil and gas reserves and present value of estimated future net revenues from proved oil and gas reserves in the periods ended March 31 are summarized below.

PROVED RESERVES

	March 31, 2016	2015	2014
Oil (Bbls):			
Proved developed – Producing	334,500	260,580	278,230
Proved developed – Non-producing	15,680	23,090	16,390
Proved undeveloped	734,170	376,070	206,930
Total	1,084,350	659,730	501,550
Natural gas (Mcf):			
Proved developed – Producing	3,356,660	3,470,970	2,982,480
Proved developed – Non-producing	1,049,400	1,113,820	1,098,990
Proved undeveloped	1,395,220	1,703,790	2,177,810
Total	5,801,280	6,288,580	6,259,280
Total net proved reserves (Boe)	2,051,230	1,707,827	1,544,763
PV-10 Value (1)	$16,121,600	$23,700,470	$24,745,250
Present value of future income tax discounted at 10%	(2,223,600)	(4,762,470)	(5,416,250)
Standardized measure of discounted future net cash flows (2)	$13,898,000	$18,938,000	$19,329,000
Prices used in Calculating Reserves: (3)			
Natural gas (per Mcf)	$1.998	$3.595	$3.67
Oil (per Bbl)	$41.76	$74.84	$94.23

(1) The PV-10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10% per annum, which is the most directly comparable GAAP financial measure. PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to

our estimated net proved reserves prior to taking into account future corporate income taxes. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. Our reconciliation of this non-GAAP financial measure is shown in the table as the PV-10, less future income taxes, discounted at 10% per annum, resulting in the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%.

(2) In accordance with SEC requirement, the standardized measure of discounted future net cash flows was computed by applying 12-month average prices for oil and gas during the fiscal year to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions.

(3) These prices reflect adjustment by lease for quality, transportation fees and regional price differentials and did not give effect to derivative transactions.

We have not filed any other oil or gas reserve estimates or included any such estimates in reports to other federal or foreign governmental authority or agency during the year ended March 31, 2016, and no major discovery is believed to have caused a significant change in our estimates of proved reserves since that date.

During the fiscal year ending March 31, 2016, 4 wells in which we own a royalty interest were developed converting reserves of approximately 66,000 mcfe from proved undeveloped to proved developed - producing. We participated in the development of 20 wells converting reserves of approximately 190,000 mcfe from proved undeveloped to proved developed - producing. The capital cost was approximately $733,000 for the 20 wells in which we own a working interest.

Oil and gas prices significantly impact the calculation of the PV-10 and the standardized measure of discounted future net cash flows. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standards Board ("FASB") pronouncements, may not necessarily be the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Productive Wells and Acreage

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections. Wells that are completed in more than one producing zone are counted as one well. The following table indicates our productive wells as of March 31, 2016:

	Gross	Net
Oil	3,386	21.2
Gas	3,075	13.3
Total Productive Wells	6,461	34.5

A gross acre is an acre in which an interest is owned. A net acre is deemed to exist when the sum of fractional ownership interests in gross acres equals one. The number of net acres is the sum of the fractional interests owned in gross acres.

The following table sets forth the approximate developed acreage in which we held a leasehold mineral or other interest as of March 31, 2016:

	Developed Acres	
	Gross	Net
Texas	354,421	3,047
Oklahoma	97,430	1,450
New Mexico	30,039	517
Louisiana	43,027	46
North Dakota	30,174	46
Kansas	9,672	24
Montana	7,868	5
Wyoming	3,898	5
Arkansas	960	5
Alabama	640	2
Mississippi	1,600	3
Colorado	1,120	1
Virginia	129	1
Total	580,978	5,152

Drilling Activities

The following table sets forth our drilling activity in wells in which we own a working interest for the years ended March 31:

	Year Ended March 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	15	.07	56	.41	34	.42
Nonproductive	-	-	1	.09	1	.01
Total	15	.07	57	.50	35	.43

We have not participated in any exploratory wells during the years ended March 31, 2016, 2015 and 2014. The information contained in the foregoing table should not be considered indicative of future drilling performance, nor should it be assumed that there is any necessary correlation between the number of productive wells drilled and the amount of oil and gas that may ultimately be recovered by us.

Net Production, Unit Prices and Costs

The following table summarizes our net oil and natural gas production, the average sales price per barrel (“bbl”) of oil and per thousand cubic feet (“mcf”) of natural gas produced and the average production (lifting) cost per unit of production for the years ended March 31:

	Year Ended March 31,		
	2016	2015	2014
Oil (a):			
Production (Bbls)	38,930	29,557	27,186
Revenue	$1,598,725	$2,069,806	$2,591,619
Average Bbls per day (e)	107	81	74
Average sales price per Bbl (b)	$41.07	$70.03	$95.33
Gas (c):			
Production (Mcf)	407,939	369,034	361,652
Revenue	$785,225	$1,267,020	$1,402,676
Average Mcf per day (e)	1,118	1,011	991
Average sales price per Mcf	$1.92	$3.43	$3.88
Production cost:			
Production cost	$944,933	$1,024,130	$943,730
Production and ad valorem taxes	$199,128	$276,690	$288,084
Equivalent Mcf (d)	641,518	546,375	524,768
Production cost per equivalent Mcf	$1.47	$1.87	$1.80
Production cost per sales dollar	$0.40	$0.31	$0.24
Total oil and gas revenue	$2,383,950	$3,336,826	$3,994,295

(a) Includes condensate.

(b) We did not have a price swap agreement on our oil production for the year ended March 31, 2016. After giving effect to our derivative instruments, the average sales price per Bbl of oil was $73.48 for year ended March 31, 2015. After giving effect to our derivative instruments, the average sales price per Bbl of oil was $93.33 for year ended March 31, 2014.

(c) Includes natural gas products.

(d) Oil production is converted to equivalent mcf at the rate of 6 mcf per bbl, representing the estimated relative energy content of natural gas to oil.

(e) Calculated on a 365 day year.

ITEM 3. LEGAL PROCEEDINGS

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. We are not aware of any legal or governmental proceedings against us, or contemplated to be brought against us, under various environmental protection statutes or other regulations to which we are subject.

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

Market Information

In September 2003, our common stock began trading on the NYSE MKT, formerly the American Stock Exchange, under the symbol "MXC". Prior to September 2003, the Company's common stock was traded on the over-the-counter bulletin board market under the symbol "MEXC". The registrar and transfer agent is Computershare Trust Company N.A., 250 Royall Street, Canton, Massachusetts, 02021 (Tel: 800-962-4284). The following table sets forth certain information as to the high and low sales price quoted for Mexco's common stock on the NYSE MKT.

		High	Low
2016:	April - June 2015	$5.65	$4.54
	July - September 2015	4.58	1.81
	October - December 2015	3.25	2.28
	January - March 2016	3.27	1.57
2015:	April - June 2014	$10.05	$6.44
	July - September 2014	8.25	6.53
	October - December 2014	7.02	5.43
	January - March 2015	5.90	4.31

On June 15, 2016, the closing sales price of our common stock on the NYSE MKT was $3.02 per share.

Stockholders

As of March 31, 2016, we had approximately 2,104,266 shares issued and 889 shareholders of record which does not include shareholders for whom shares are held in a "nominee" or "street" name.

Dividends

We have never declared or paid any cash dividends on our common stock. We currently intend to retain future earnings and other cash resources, if any, for the operation and development of our business and do not anticipate paying any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our Board of Directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion. In addition, our current bank loan prohibits us from paying cash dividends on our common stock. Any future dividends may also be restricted by any loan agreements which we may enter into from time to time.

Securities Authorized for Issuance Under Compensation Plans

The following table includes certain information about our Employee Incentive Stock Plan as of March 31, 2016, which has been approved by our stockholders.

	Number of Shares Authorized for Issuance under Plan	Number of Shares to be Issued upon Exercise of Outstanding Options	Weighted Average Exercise Price of Outstanding Options	Number of Shares Remaining Available for Future Issuance under Plan
2009 Plan	200,000	153,600	$ 6.52	45,000
Total	200,000	153,600	$ 6.52	45,000

Issuer Repurchases

In June 2015, the Board of Directors authorized the use of up to $250,000 to repurchase shares of our common stock for the treasury account. This program does not have an expiration date. Under the repurchase program, shares of common stock may be purchased from time to time through open market purchases or other transactions. The amount and timing of repurchases will be subject to the availability of stock, prevailing market conditions, the trading price of the stock, our financial performance and other conditions. Repurchases may also be made from time-to-time in connection with the settlement of our share-based compensation awards. Repurchases will be funded from cash flow from operations.

There were no shares of our common stock repurchased for the treasury account during the fiscal year ended March 31, 2016. During the fiscal year ended March 31, 2015, we repurchased 1,000 shares for the treasury at an aggregate cost of $5,009. There were no shares of our common stock repurchased for the treasury account during the fiscal year ended March 31, 2014.

ITEM 6. SELECTED CONSOLIDATED FINANCIAL DATA

Not applicable.

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

The following discussion is intended to provide information relevant to an understanding of our financial condition, changes in our financial condition and our results of operations and cash flows and should be read in conjunction with our consolidated financial statements and notes thereto included elsewhere in this Form 10-K.

Liquidity and Capital Resources and Commitments

Historically, we have funded our operations, acquisitions, exploration and development expenditures from cash generated by operating activities, bank borrowings and issuance of common stock. Our primary financial resource is our base of oil and gas reserves. We pledge our producing oil and gas properties to secure our revolving line of credit. We do not have any delivery commitments to provide a fixed and determinable quantity of our oil and gas under any existing contract or agreement.

Due to depressed commodity price environment, we are applying financial discipline to all aspects of our business. In order to meet obligations, we will continue to sell non-core assets, if necessary. This will enable us to participate in any Midland and Delaware Basin projects.

Our long term strategy is on increasing profit margins while concentrating on obtaining reserves with low cost operations by acquiring and developing oil and gas properties with potential for long-lived production. We focus our efforts on the acquisition of royalties and working interest, non-operated properties in areas with significant development potential.

For the year ending March 31, 2016, cash flow from operations was $175,502, an 85% decrease when compared to the corresponding period of fiscal 2015. Net cash of $370,000 was used to reduce the line of credit and net cash of $132,427 was provided by activity associated with oil and gas properties and other property and equipment. Accordingly, net cash decreased $62,071.

We had working capital of $23,150 as of March 31, 2016 compared to working capital of $166,650 as of March 31, 2015, a decrease of $143,500 for the reasons set forth below.

Oil and Natural Gas Property Transactions

During fiscal year 2016, Mexco participated in the last of three horizontal wells in the Wolfcamp B formation of the Spraberry Field of Martin County, Texas. All three wells, operated by QEP Energy Company, are currently producing. Our share of the costs to drill and complete these wells for our .2125% working interest (.159% net revenue interest) was approximately $76,000.

We participated in the completion of three horizontal wells in the Penn Detrital formation of the F A Hogg Field of Winkler County, Texas. All three wells in two units, operated by Apache Corporation, are currently producing on approximately 1,900 acres. Mexco’s working interest in these wells is .4167% (.3125% net revenue interest). Our share of the costs to complete these wells was approximately $54,000 in fiscal 2016.

A joint venture in which Mexco is a working interest owner participated in two wells completed in Wolfcamp A and B formations using horizontal drilling and multi-stage fracture stimulation on a 1,125-acre tract in Reagan County, Texas. These wells, operated by Bold Energy III, LLC, are currently producing. Our share of the costs to drill, fracture and complete these two wells for our approximately 3.13% working interest including a carried interest from and at the expense of Bold (2.48% net revenue interest) was approximately $411,000 to date ($224,000 of which was expended in fiscal 2016).

Mexco participated in the drilling and completion of one horizontal well and the completion of another horizontal well in the Third Bone Spring formation in Lea County, New Mexco. Both wells are operated by XTO Energy, Inc., a subsidiary of Exxon Mobil Corporation. Mexco's share of the costs during fiscal 2016 for these wells was approximately $267,000 for our 2.78% working interest (1.95% net revenue interest).

Mexco participated in the drilling and completion of two horizontal wells and the completion of another horizontal well in the Lower Avalon formation located in Lea County, New Mexico and operated by Concho Resources, Inc. All three wells are now producing. During fiscal 2016, Mexco has expended $96,000 for our approximate .60% working interest (.45% net revenue interest).

Mexco participated in the drilling and completion of one horizontal well and one salt water disposal well and the completion of two other horizontal wells in the Red Hills (Avalon) Field of Lea County, New Mexico. These wells, operated by Concho Resources, Inc. are now all producing. Mexco's share of the costs through March 31, 2016 for these wells as well as purchase of additional interests was approximately $131,000 for our approximately .49% working interest (.32% net revenue interest).

Mexco also participated in the drilling and completion of four horizontal wells and one vertical well in the Berry (Third Bone Spring) Field of Lea County, New Mexico. The wells, operated by Concho Resources, Inc. are now all producing. Mexco's share of the costs through March 31, 2016 for these wells was approximately $50,000 for our approximately .29% working interest (.18% net revenue interest).

Mexco participated in the drilling and completion of three horizontal wells and one salt water disposal well and the completion of another horizontal well in the Avalon Shale portion of the Bone Spring formation in Lea County, New Mexico. These wells, operated by Concho Resources, Inc. are now all producing. Mexco's share of the costs through March 31, 2016 for these wells as well as purchase of additional interests was approximately $253,000. Mexco's working interests in these wells now range from .74% to 1.07% (.44% to .60% net revenue interest).

In November 2015, Mexco's purchaser exercised a six month lease assignment extension option for which the Company received $112,000 for a three year assignment of a leasehold interest in 320 net acres (640 gross acres) in

Upton County, Texas. The purchaser paid Mexco $2,000 per acre for a total of $640,000. Mexco also retained a 1% overriding royalty interest in this acreage. This acreage has the potential for horizontal development in multiple zones of the horizontal Wolfcamp formation centered in the southern Midland Basin. The purchaser advises that he has obtained rights to explore the balance of the undivided 640 acres from Apache Corporation and that Parsley Energy, Inc. plans to develop this property.

Two royalty interest wells drilled and recently began producing in Upton County, Texas by Pioneer Natural Resources Company, two more wells are currently undergoing completion procedures and 3 more wells are drilling, all being horizontal wells with 10,000 feet of laterals at no expense to us. These wells are located in part on 411 acres in which Mexco has retained a 1% overriding royalty interest.

In July 2015, Mexco began receiving royalties from three new horizontal wells operated by Pioneer in Reagan County, Texas at no expense to us.

At March 31, 2016, we reported estimated proved undeveloped reserves (“PUDs”) of 5.8 bcfe, which accounted for 47% of our total estimated proved oil and gas reserves. This figure primarily consists of a projected 67 new wells, four of which we plan to cause to be drilled in fiscal 2019 by an unrelated third party in addition to the three wells currently operated by Mexco on this property. Regarding the remaining 63 PUD locations operated by others, one well is currently being drilled with plans for 14 wells to follow in 2017, 14 wells in 2018, 16 wells in 2019 and 18 wells in 2020.

During fiscal 2016, but effective April 1, 2016, Mexco sold various interests in non-core oil and gas properties located in Howard, Johnson, Martin, Midland and Reagan Counties, Texas for $518,760 in aggregate. Of these received funds, $270,000 was used to reduce the balance of Mexco's indebtedness.

We are participating in other projects and are reviewing projects in which we may participate. The cost of such projects would be funded, to the extent possible, from existing cash balances and cash flow from operations. The remainder may be funded through borrowings on the credit facility and, if appropriate, sales of our common stock. See Note 5 of Notes to Consolidated Financial Statements for a description of our revolving credit agreement with Bank of America, N.A.

Crude oil and natural gas prices remained significantly depressed during the last year. Lower product prices reduce our cash flow from operations and diminish the present value of our oil and gas reserves. Lower product prices also offer us less incentive to assume the drilling risks that are inherent in our business. The volatility of the energy markets makes it extremely difficult to predict future oil and natural gas price movements with any certainty. For example in the last twelve months, the West Texas Intermediate ("WTI") posted price for crude oil has ranged from a low of $22.75 per bbl in February 2016 to a high of $58.00 per bbl in June 2015. The Henry Hub Spot Market Price ("Henry Hub") for natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $3.04 per MMBtu in May 2015. These are at a level not seen since 2003.

On March 31, 2016 the WTI posted price for crude oil was $34.75 per bbl and the Henry Hub spot price for natural gas was $1.98 per MMBtu. Management is of the opinion that cash flow from operations will be sufficient to provide adequate liquidity for the next fiscal year.

Results of Operations

Fiscal 2016 Compared to Fiscal 2015

We had a net loss of $3,979,685 for the year ended March 31, 2016 compared to a net loss of $340,986 for the year ended March 31, 2015.

Oil and gas sales. Revenue from oil and gas sales was $2,383,950 for the year ended March 31, 2016, a 29% decrease from $3,336,826 for the year ended March 31, 2015. This resulted from a decrease in oil and gas prices partially offset by an increase in oil and gas production. The following table sets forth our oil and gas revenues, production quantities and average prices received during the fiscal years ended March 31:

	2016	2015	% Difference	
Oil:				
Revenue	$1,598,725	$2,069,806	(22.8	%)
Volume (bbls)	38,930	29,557	31.7	%
Average Price (per bbl) (a)	$41.07	$70.03	(41.4	%)
Gas:				
Revenue	$785,225	$1,267,020	(38.0	%)
Volume (mcf)	407,939	369,034	10.5	%
Average Price (per mcf)	$1.92	$3.43	(44.0	%)

(a) We did not have a price swap agreement on our oil production for the year ended March 31, 2016. After giving effect to our derivative instruments, the average sales price per Bbl of oil was $73.48 for year ended March 31, 2015.

Production and exploration. Production costs were $1,144,061 in fiscal 2016, a 12% decrease from $1,300,820 in fiscal 2015. This was the result of a decrease in production and ad valorem taxes due to the decrease in sales as a result of the decreased oil and gas prices. In addition, lease operating expenses decreased as a result of lowering service costs due to the depressed market.

Impairment of oil and gas properties. The impairment in the carrying value of our oil and natural gas properties was $2,984,410 for the year ended March 31, 2016. This was due to downward adjustments to the economically recoverable proved reserves associated with decreases in estimated realized oil and natural gas prices.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expense was $1,572,738 in fiscal 2016, a 15% increase from $1,362,862 in fiscal 2015. This was due to an increase in oil and gas production and an increase in the full cost pool amortization base prior to the impairment in the second and third quarters of fiscal 2016.

General and administrative expenses. General and administrative expenses were $1,155,183 for the year ended March 31, 2016, a 7% decrease from $1,239,750 for the year ended March 31, 2015. This was primarily due to a decrease in salary, insurance and subscriptions and dues expenses.

Interest expense. Interest expense was $171,375 in fiscal 2016, a 73% increase from $99,240 in fiscal 2015, due to an increase in borrowings.

Income taxes. There was an income tax benefit of $660,870 in fiscal 2016 compared to an income tax benefit of $197,499 in fiscal 2015. The effective tax rate for fiscal 2016 was (14%) compared to (37%) for fiscal 2015. This decrease in the effective income tax rate is primarily due to the tax benefit at expected rates being offset by an increase in our valuation allowance. Based on the material write-downs of the carrying value of our oil and natural gas properties for the year ending March 31, 2016, we are in a net deferred tax asset position at year end. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated was the cumulative loss incurred over the two-year period ending March 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased, or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

Fiscal 2015 Compared to Fiscal 2014

We had a net loss of $340,986 for the year ended March 31, 2015 compared to net income of $301,113 for the year ended March 31, 2014.

Oil and gas sales. Revenue from oil and gas sales was $3,336,826 for the year ended March 31, 2015, a 16% decrease from $3,994,295 for the year ended March 31, 2014. This resulted from a decrease in oil and gas prices partially offset by an increase in oil and gas production. The following table sets forth our oil and gas revenues, production quantities and average prices received during the fiscal years ended March 31:

	2015	2014	% Difference
Oil:			
Revenue	$2,069,806	$2,591,619	(20.1 %)
Volume (bbls)	29,557	27,186	8.7 %
Average Price (per bbl) (a)	$70.03	$95.33	(26.5 %)
Gas:			
Revenue	$1,267,020	$1,402,676	(9.7 %)
Volume (mcf)	369,034	361,652	2.0 %
Average Price (per mcf)	$3.43	$3.88	(11.6 %)

(a) After giving effect to our derivative instruments, the average sales price per Bbl of oil was $73.48 for year ended March 31, 2015. After giving effect to our derivative instruments, the average sales price per Bbl of oil was $93.33 for year ended March 31, 2014.

Production and exploration. Production costs were $1,300,820 in fiscal 2015, a 6% increase from $1,231,814 in fiscal 2014. This was the result of an increase in lease operating expenses resulting from acquisitions of working interests of non-operated properties partially offset by a decrease in production taxes due to the decrease in oil and gas revenue.

Depreciation, depletion and amortization. Depreciation, depletion and amortization ("DD&A") expense was $1,362,862 in fiscal 2015, an 18% increase from $1,151,482 in fiscal 2014. This was due to an increase in oil and gas production and an increase in the full cost pool partially offset by an increase in oil and gas reserves.

General and administrative expenses. General and administrative expenses were $1,239,750 for the year ended March 31, 2015, a 9% increase from $1,136,939 for the year ended March 31, 2014. This was primarily due to an increase in accounting, salary and insurance expenses.

Interest expense. Interest expense was $99,240 in fiscal 2015, a 52% increase from $65,387 in fiscal 2014, due to an increase in borrowings.

Derivatives. Derivative realized gains of $102,069 were recorded during the year ended March 31, 2015 resulting from our oil swap agreement. This compared to derivative losses of $99,262 recorded during the year ended March 31, 2014 ($54,281 of realized losses and $44,981 of unrealized losses.)

Income taxes. There was an income tax benefit of $197,499 in fiscal 2015 compared to an income tax expense of $11,750 in fiscal 2014. The effective tax rate for fiscal 2015 was (37%) compared to 4% for fiscal 2014.

Contractual Obligations

We have no off-balance sheet debt or unrecorded obligations and have not guaranteed the debt of any other party. The following table summarizes future payments we are obligated to make based on agreements in place as of March 31, 2016:

	Payments due in:			
	Total	less than 1 year	1 - 3 years	over 3 years
Contractual obligations:				
Secured bank line of credit (1)	$5,580,000	$-	$-	$5,580,000
Leases (2)	$42,460	$23,440	$19,020	$-

(1) These amounts represent the balances outstanding under the bank line of credit. These repayments assume that interest will be paid on a monthly basis, no additional funds will be drawn and does not include estimated interest of $163,773 less than 1 year, $491,319 1-3 years and $109,182 over 3 years.

(2) The lease amount represents the monthly rent amount for our principal office space in Midland, Texas under one three year lease agreement effective April 1, 2013 and a second three year lease agreement effective April 1, 2014. In February 2016, the option to renew the 2013 lease for two years was exercised. The total obligation for the

remainder of the leases is $60,939 which includes $18,479 billed to and reimbursed by our majority shareholder for his portion of the shared office space.

Alternative Capital Resources

Although we have primarily used cash from operating activities and funding from the line of credit as our primary capital resources, we have in the past, and could in the future, use alternative capital resources. These could include joint ventures, carried working interests and the sale of assets and/or issuances of common stock through a private placement or public offering of our common stock.

Other Matters

Critical Accounting Policies and Estimates

In preparing financial statements, management makes informed judgments, estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. On an ongoing basis, management reviews its estimates, including those related to litigation, environmental liabilities, income taxes, fair value and determination of proved reserves. Changes in facts and circumstances may result in revised estimates and actual results may differ from these estimates.

The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Full Cost Method of Accounting for Crude Oil and Natural Gas Activities. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in crude oil and natural gas activities. Two methods are prescribed: the successful efforts method and the full cost method. We have chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation ("ARO") when incurred.

Gain or loss on the sale or other disposition of oil and gas properties is not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of crude oil and natural gas properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of crude oil and natural gas properties under the successful efforts method. As a result our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher DD&A rate on our crude oil and natural gas properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us more susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. Our crude oil and natural gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from the full cost method of accounting.

Ceiling Test. Companies that use the full cost method of accounting for oil and gas exploration and development activities are required to perform a ceiling test each quarter. The full cost ceiling test is an impairment test to determine a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves plus the lower of cost or fair market value of unproved properties. If net capitalized costs of crude oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This impairment to our oil and gas properties does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings.

The risk that we will be required to write down the carrying value of crude oil and natural gas properties increases when crude oil and natural gas prices are depressed or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for natural gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher crude oil and natural gas prices may have increased the ceiling applicable to the subsequent period.

Estimates of our proved reserves are based on the quantities of oil and gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Our reserve estimates and the projected cash flows are derived from these reserve estimates, in accordance with SEC guidelines by an independent engineering firm based in part on data provided by us. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgment of the persons preparing the estimate. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

It should not be assumed that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, the cost ceiling represents the present value (discounted at 10%) of net cash flows from sales of future production using the average price over the prior 12-month period.

The estimates of proved reserves materially impact DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost projects.

Use of Estimates. In preparing financial statements in conformity with accounting principles generally accepted in the United States of America, management is required to make informed judgments, estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. In addition, significant estimates are used in determining year end proved oil and gas reserves. Although management believes its estimates and assumptions are reasonable, actual results may differ materially from those estimates. The estimate of our oil and natural gas reserves, which is used to compute DD&A and impairment of oil and gas properties, is the most significant of the estimates and assumptions that affect these reported results.

Excluded Costs. Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent investments in unproved properties and major development projects. These costs are excluded until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the DD&A pool). Impairments transferred to the DD&A pool increase the DD&A rate.

Revenue Recognition. We recognize crude oil and natural gas revenue from our interest in producing wells as crude oil and natural gas are sold from those wells, net of royalties. We utilize the sales method to account for gas production volume imbalances. Under this method, income is recorded based on our net revenue interest in production taken for delivery.

Asset Retirement Obligations. The estimated costs of plugging, restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated by the units of production method. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all periods presented, we have included estimated future costs of abandonment and dismantlement in the full cost amortization base and amortize these costs as a component of our depletion expense.

Derivatives. The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. All derivative financial instruments are recorded at fair value on the balance sheet as either assets or liabilities. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value in the Consolidated Statements of Operations under the caption "Gain (loss) on derivative instruments."

Gas Balancing. Gas imbalances are accounted for under the sales method whereby revenues are recognized based on production sold. A liability is recorded when our excess takes of natural gas volumes exceed our estimated remaining recoverable reserves (over produced). No receivables are recorded for those wells where Mexco has taken less than its ownership share of gas production (under produced).

Stock-based Compensation. We use the Binomial option pricing model to estimate the fair value of stock based compensation expenses at grant date. This expense is recognized as compensation expense in our financial statements over the vesting period. We recognize the fair value of stock based compensation awards as wages in the Consolidated Statements of Operations based on a graded-vesting schedule over the vesting period.

Accounts Receivable. Our accounts receivable include trade receivables from joint interest owners and oil and gas purchasers. Credit is extended based on an evaluation of a customer's financial condition and, generally, is uncollateralized. Accounts receivable under joint operating agreements have a right of offset against future oil and gas revenues if a producing well is completed. The collectability of receivables is assessed and an allowance is made for any doubtful accounts. The allowance for doubtful accounts is determined based on our previous loss history.

Income Taxes. The Company recognizes deferred tax assets and liabilities for future tax consequences of temporary differences between the carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates applicable to the years in which those differences are expected to be settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in net income in the period that includes the enactment date. Any interest and penalties are recorded as interest expense and general and administrative expense, respectively.

Other Property and Equipment. Provisions for depreciation of office furniture and equipment are computed on the straight-line method based on estimated useful lives of three to ten years.

Recent Accounting Pronouncements. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09, "Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting". The amendment is to simplify several aspects of the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in ASU No. 2016-09 are effective for interim and annual reporting periods beginning after December 15, 2016. The Company is currently assessing the impact of ASU No. 2016-09 on the consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, Topic 842 Leases, which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard is effective for fiscal years beginning after December 15, 2018, and interim periods thereafter. Early adoption is permitted. We are currently evaluating the effect the new guidance will have on our consolidated financial statements.

In January 2016, the FASB issued authoritative guidance that amends existing requirements on the classification and measurement of financial instruments. The standard principally affects accounting for equity investments and financial liabilities where the fair value option has been elected. The guidance is effective for fiscal periods after December 15, 2017, and interim periods thereafter. Early adoption of certain provisions is permitted. We are currently evaluating the effect the new guidance will have on our financial statements.

In November 2015, the FASB issued ASU No. 2015-17, Topic 740 Income Taxes: Balance Sheet Classification of Deferred Taxes which requires all deferred income tax liabilities and assets to be presented as noncurrent in a classified balance sheet. Currently, entities are required to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet. The new standard will become effective for Mexco beginning on April 1, 2017, with the option to early adopt, and can be applied either prospectively or retrospectively. The adoption of this guidance will have no impact on our results of operations or cash flows. The reclassification of amounts from current to noncurrent could affect the presentation of our balance sheet.

In February 2015, the FASB issued ASU No. 2015-02, Topic 810: Consolidation which amends the current consolidation guidance. ASU No. 2015-02 is effective for Mexco as of April 1, 2016. Management is assessing the standard update and does not believe there will be a significant impact on our consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, Subtopic 205-40: Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern which provides guidance on determining when and how reporting entities must disclose going-concern uncertainties in their financial statements. ASU No. 2014-15 is effective for Mexco for the fiscal year ending March 31, 2017 and interim periods thereafter and early adoption is permitted. Management does not expect the adoption of this ASU to have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Topic 606: Revenue from Contracts with Customers. This ASU provides guidance concerning the recognition and measurement of revenue from contracts with customers. The effective date for ASU 2014-09 was delayed through the issuance of ASU 2015-14, Revenue from Contracts with Customers – Deferral of the Effective Date, to annual and interim periods beginning in 2018 and is required to be adopted using either the retrospective or cumulative effect transition method, with early adoption permitted in 2017. Management is evaluating the effect, if any this pronouncement will have on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary source of market risk for us includes fluctuations in commodity prices and interest rates. All of our financial instruments are for purposes other than trading.

Interest Rate Risk. On March 31, 2016, we had an outstanding loan balance of $5,580,000 under our $5.63 million revolving credit agreement, which bears interest at an annual rate equal to the British Bankers Association London Interbank Offered Rate ("BBA LIBOR") daily floating rate, plus 3.0 percentage points. If the interest rate on our bank debt increases or decreases by one percentage point our annual pretax income would change by $55,800 based on borrowings at March 31, 2016.

Credit Risk. Credit risk is the risk of loss as a result of nonperformance by other parties of their contractual obligations. Our primary credit risk is related to oil and gas production sold to various purchasers and the receivables are generally not collateralized. At March 31, 2016, our largest credit risk associated with any single purchaser was $45,253 or 18% of our total oil and gas receivables. We are also exposed to credit risk in the event of nonperformance from any of our working interest co-owners. At March 31, 2016, our largest credit risk associated with any working interest co-owner was $10,464 or 35% of our total trade receivables. We have not experienced any significant credit losses.

Energy Price Risk. Our most significant market risk is the pricing for natural gas and crude oil. Our financial condition, results of operations, and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. Prices for oil and natural gas fluctuate widely. We cannot predict future oil and natural gas prices with any certainty. Historically, the markets for oil and gas have been volatile, and they are likely to continue to be volatile.

Factors that can cause price fluctuations include the level of global demand for petroleum products, foreign supply of oil and gas, the establishment of and compliance with production quotas by oil-exporting countries, weather conditions, the price and availability of alternative fuels and overall political and economic conditions in oil producing countries.

Declines in oil and natural gas prices will materially adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Changes in oil and gas prices impact both estimated future net revenue and the estimated quantity of proved reserves. Any reduction in reserves, including reductions due to price fluctuations, can reduce the borrowing base under our revolving credit facility and adversely affect the amount of cash flow available for capital expenditures and our ability to obtain additional capital for our acquisition, exploration and development activities. In addition, a noncash write-down of our oil and gas properties could be required under full cost accounting rules if prices declined significantly, even if it is only for a short period of time. See Critical Accounting Policies and Estimates — Ceiling Test under Item 7 of this report on Form 10-K. Lower prices may also reduce the amount of crude oil and natural gas that can be produced economically. Thus, we may experience material increases or decreases in reserve quantities solely as a result of price changes and not as a result of drilling or well performance.

Similarly, any improvements in oil and gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Our financial results are more sensitive to movements in natural gas prices than oil prices because most of our reserves are natural gas. If the average oil price had increased or decreased by five dollars per barrel for fiscal 2016, our oil and gas revenue would have changed by $194,650. If the average gas price had increased or decreased by one dollar per mcf for fiscal 2016, oil and gas revenue would have changed by $407,939.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears on pages F1 through F21 hereof and are incorporated herein by reference.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management's Annual Report on Internal Control over Financial Reporting. The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Exchange Act Rule 13a-15(f) and 15d-15(f). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel, and a written Code of Conduct adopted by our Board of Directors, applicable to all directors, officers and employees of Mexco.

Our chief executive officer and chief financial officer assessed the effectiveness our internal control over financial reporting using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in the 2013 "Internal Control - Integrated Framework". Based upon that evaluation, our chief executive officer and chief financial officer concluded that our internal control over financial reporting was effective as of March 31, 2016.

Evaluation of Disclosure Controls and Procedures. We maintain disclosure controls and procedures to ensure that the information we must disclose in our filings with the SEC is recorded, processed, summarized and reported on a timely basis. At the end of the period covered by this report, our principal executive officer and principal financial officer reviewed and evaluated the effectiveness of our disclosure controls and procedures, as defined in Exchange Act Rule 13a-15(e). Based on such evaluation, such officers concluded that, as of March 31, 2016, our disclosure controls and procedures were effective.

Changes in Internal Control over Financial Reporting. No changes in the Company's internal control over financial reporting occurred during the year ended March 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

See “Mexco Energy Corporation Board of Directors”, “Named Executive Officers Who Are Not Directors”, “Section 16(a) Beneficial Ownership Reporting Compliance”, “Corporate Governance and Code of Business Conduct” and “Meetings and Committees of the Board of Directors” in the Proxy Statement of Mexco Energy Corporation for our Annual Meeting of Stockholders to be held September 13, 2016 (“Proxy Statement”) to be filed with the SEC within 120 days after the end of our fiscal year ended March 31, 2016, which is incorporated herein by reference.

The information required by this item with respect to executive officers of the Company is also set forth in Part I of this report.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be contained in the Proxy Statement under the caption “Executive Compensation”, and is hereby incorporated herein by reference.

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

The information required by this item will be contained in the Proxy Statement under the captions “Security Ownership of Certain Beneficial Owners and Management” and “Employee Incentive Stock Option Plans”, and is hereby incorporated herein by reference.

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

The information required by this item will be contained in the Proxy Statement under the captions “Certain Relationships and Related Transactions” and “Meetings and Committees of the Board of Directors”, and is hereby incorporated by reference herein.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be contained in the Proxy Statement under the caption “Audit Fees and Services”, and is hereby incorporated by reference herein.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Consolidated Financial Statements. For a list of the consolidated financial statements filed as part of this Form 10-K, see the “Index to Consolidated Financial Statements” set forth on page F1 of this report.

Financial Statement Schedules. All schedules have been omitted because they are not applicable, not required under the instructions or the information requested is set forth in the consolidated financial statements or related notes thereto.

Exhibits. For a list of the exhibits required by this Item and accompanying this Form 10-K see the "Index to Exhibits" set forth on page F22 of this report.

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.

MEXCO ENERGY CORPORATION

By:*/s/ Nicholas C. Taylor*	By:*/s/ Tamala L. McComic*
Chairman of the Board and Chief Executive Officer	President and Chief Financial Officer

Dated: June 28, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below as of June 28, 2016, by the following persons on behalf of the Registrant and in the capacity indicated.

/s/ Nicholas C. Taylor
Nicholas C. Taylor
Chief Executive Officer, Chairman of the Board of Directors

/s/ Tamala L. McComic
Tamala L. McComic
Chief Financial Officer, President, Treasurer and Assistant Secretary

/s/ Michael J. Banschbach
Michael J. Banschbach
Director

/s/ Kenneth L. Clayton
Kenneth L. Clayton
Director

/s/ Thomas R. Craddick
Thomas R. Craddick
Director

/s/ Paul G. Hines
Paul G. Hines
Director

/s/ Christopher M. Schroeder
Christopher M. Schroeder
Director

Glossary of Abbreviations and Terms

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report.

Basin. A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

BBA LIBOR. British Bankers Association London Interbank Offered Rate. BBA Libor is the most widely used rate for short term interest rates worldwide.

Bbl. One stock tank barrel, or 42 U.S. gallons of liquid volume, used herein in reference to crude oil, condensate or natural gas liquids hydrocarbons.

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

BTU. British thermal unit.

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

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Credit Facility. A line of credit provided by a bank or group of banks, secured by oil and gas properties.

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

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Development well. A well drilled into a proved 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 such that proceeds from the sale of such production exceed production expenses and taxes.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

Extensions and discoveries. As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

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

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

Gross acres or wells. Refers to the total acres or wells in which the Company owns any amount of working interest.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter and explore for, drill for, produce, store and remove oil and natural gas from the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf for each Bbl of oil.

MMBtu. One million British thermal units of energy commonly used to measure heat value or energy content of natural gas.

Natural gas liquids ("NGLs"). Liquid hydrocarbons that have been extracted from natural gas, such as ethane, propane, butane and natural gasoline.

Net acres or wells. Refers to gross acres or wells multiplied, in each case, by the percentage interest owned by the Company.

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

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Oil. Crude oil or condensate.

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

Overriding royalty interest ("ORRI"). A royalty interest that is created out of the operating or working interest. Its term is coextensive with that of the operating interest from which it was created.

Pay zone. A geological deposit in which oil and natural gas is found in commercial quantities.

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

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

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed nonproducing reserves ("PDNP"). Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves ("PDP"). Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Proved developed reserves. The combination of proved developed producing and proved developed nonproducing reserves.

Proved reserves. The estimated quantities of oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves ("PUD"). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

PV-10. When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10%.

Recompletion. A process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Re-entry. Entering an existing well bore to redrill or repair.

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

Royalty. An interest in an 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.

Shut in. A well suspended from production or injection but not abandoned.

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 640-acre spacing) and is often established by regulatory agencies.

Standardized measure of discounted future net cash flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a 10% annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas reserve data contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

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

Unit. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Wellbore. The hole drilled by the bit that is equipped for crude oil or natural gas production on a completed well. Also called well or borehole.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce 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.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders

Mexco Energy Corporation

We have audited the accompanying consolidated balance sheets of Mexco Energy Corporation (a Colorado corporation) and Subsidiaries (the "Company") as of March 31, 2016 and 2015 and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended March 31, 2016. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, 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. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Mexco Energy Corporation and Subsidiaries as of March 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
June 28, 2016

Mexco Energy Corporation and Subsidiaries

CONSOLIDATED BALANCE SHEETS

	March 31, 2016	March 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$34,013	$96,084
Accounts receivable:		
Oil and gas sales	248,145	384,485
Trade	29,880	64,584
Prepaid costs and expenses	43,284	44,618
Total current assets	355,322	589,771
Property and equipment, at cost Oil and gas properties, using the full cost method	40,365,197	40,563,443
Other	107,484	106,792
Accumulated depreciation, depletion and amortization	(24,395,184)	(19,838,036)
Property and equipment, net	16,077,497	20,832,199
Other noncurrent assets	34,441	48,980
Total assets	$16,467,260	$21,470,950
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$332,172	$423,121
Long-term debt	5,580,000	5,950,000
Asset retirement obligations	1,211,077	1,230,216
Deferred income tax liabilities	-	660,870
Total liabilities	7,123,249	8,264,207
Commitments and contingencies		
Stockholders' equity		
Preferred stock - $1.00 par value; 10,000,000 shares authorized; none outstanding	-	-
Common stock - $0.50 par value; 40,000,000 shares authorized; 2,104,266 shares issued and 2,037,266 shares outstanding as of March 31, 2016 and 2015, respectively	1,052,133	1,052,133
Additional paid-in capital	7,191,984	7,075,031
Retained earnings	1,445,895	5,425,580
Treasury stock, at cost (67,000 shares)	(346,001)	(346,001)
Total stockholders' equity	9,344,011	13,206,743
	$16,467,260	$21,470,950

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

F-3

Mexco Energy Corporation and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended March 31,

	2016	2015	2014
Operating revenues:			
Oil and gas	$2,383,950	$3,336,826	$3,994,295
Other	37,842	53,179	47,646
Total operating revenues	2,421,792	3,390,005	4,041,941
Operating expenses:			
Production	1,144,061	1,300,820	1,231,814
Accretion of asset retirement obligation	35,155	27,932	44,366
Impairment of long-lived assets	2,984,410	-	-
Depreciation, depletion and amortization	1,572,738	1,362,862	1,151,482
General and administrative	1,155,183	1,239,750	1,136,939
Total operating expenses	6,891,547	3,931,364	3,564,601
Operating (loss) income	(4,469,755)	(541,359)	477,340
Other income (expenses):			
Interest income	575	45	172
Interest expense	(171,375)	(99,240)	(65,387)
Gain (loss) on derivative instruments	-	102,069	(99,262)
Net other (expense) income	(170,800)	2,874	(164,477)
(Loss) earnings before provision for income taxes	(4,640,555)	(538,485)	312,863
Income tax (benefit) expense:			
Current	-	-	6,500
Deferred	(660,870)	(197,499)	5,250
	(660,870)	(197,499)	11,750
Net (loss) income	$(3,979,685)	$(340,986)	$301,113
(Loss) income per common share:			
Basic:	$(1.95)	$(0.17)	$0.15
Diluted:	$(1.95)	$(0.17)	$0.15
Weighted average common shares outstanding:			
Basic:	2,037,266	2,038,250	2,036,950
Diluted:	2,037,266	2,038,250	2,042,184

The accompanying notes to the consolidated financial statements

are an integral part of these statements.

F-4

Mexco Energy Corporation and Subsidiaries

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

Years ended March 31, 2016, 2015 and 2014

	Common Stock Par Value	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Total Stockholders' Equity
Balance at April 1, 2013	$1,051,433	$(340,992)	$6,761,091	$5,465,453	$12,936,985
Net income	-	-	-	301,113	301,113
Issuance of stock through options exercised	700	-	8,106	-	8,806
Stock based compensation	-	-	152,448	-	152,448
Balance at March 31, 2014	$1,052,133	$(340,992)	$6,921,645	$5,766,566	$13,399,352
Net loss	-	-	-	(340,986)	(340,986)
Purchase of stock	-	(5,009)	-	-	(5,009)
Stock based compensation	-	-	153,386	-	153,386
Balance at March 31, 2015	$1,052,133	$(346,001)	$7,075,031	$5,425,580	$13,206,743
Net loss	-	-	-	(3,979,685)	(3,979,685)
Stock based compensation	-	-	116,953	-	116,953
Balance at March 31, 2016	$1,052,133	$(346,001)	$7,191,984	$1,445,895	$9,344,011

SHARE ACTIVITY

	2016	2015	2014
Common stock shares, issued:			
At beginning of year	2,104,266	2,104,266	2,102,866
Issued	-	-	1,400
At end of year	2,104,266	2,104,266	2,104,266
Common stock shares, held in treasury:			
At beginning of year	(67,000)	(66,000)	(66,000)
Acquisitions	-	(1,000)	-
At end of year	(67,000)	(67,000)	(66,000)
Common stock shares, outstanding At end of year	2,037,266	2,037,266	2,038,266

The accompanying notes to the consolidated financial statements

are an integral part of these statements.

Mexco Energy Corporation and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended March 31,

	2016	2015	2014
Cash flows from operating activities:			
Net (loss) income	$(3,979,685)	$(340,986)	$301,113
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Deferred income tax (benefit) expense	(660,870)	(197,499)	5,250
Stock-based compensation	116,953	153,386	152,448
Depreciation, depletion and amortization	1,572,738	1,362,862	1,151,482
Accretion of asset retirement obligations	35,155	27,932	44,366
(Gain) loss on derivative instruments	-	(102,069)	99,262
Impairment of oil and gas properties	2,984,410	-	-
Changes in assets and liabilities, net of business combination:			
Decrease (increase) in accounts receivable	171,044	197,173	(90,901)
Decrease (increase) in prepaid expenses	1,334	(15,814)	(9,523)
Decrease in noncurrent assets	-	-	109,215
(Decrease) increase in income tax payable	-	(6,500)	6,500
(Decrease) increase in accounts payable and accrued expenses	(65,577)	98,494	43,289
Net cash provided by operating activities	175,502	1,176,979	1,812,501
Cash flows from investing activities:			
Additions to oil and gas properties	(1,138,106)	(4,777,979)	(2,150,478)
Additions to other property and equipment	(693)	(12,436)	(2,030)
Settlement of asset retirement obligations	(51,632)	(39,352)	(63,230)
Settlement of derivatives	-	57,089	(54,281)
Proceeds from sale of oil and gas properties and equipment	1,322,858	15,710	963,388
Net cash provided by (used in) investing activities	132,427	(4,756,968)	(1,306,631)
Cash flows from financing activities:			
Acquisition of treasury stock	-	(5,009)	-
Proceeds from exercise of stock options	-	-	8,806
Reduction of long-term debt	(770,000)	(150,000)	(1,375,000)
Proceeds from long-term debt	400,000	3,675,000	850,000
Net cash (used in) provided by financing activities	(370,000)	3,519,991	(516,194)
Net decrease in cash and cash equivalents	(62,071)	(59,998)	(10,324)
Cash and cash equivalents at beginning of period	96,084	156,082	166,406
Cash and cash equivalents at end of period	$34,013	$96,084	$156,082

Supplemental disclosure of cash flow information:			
Cash paid for interest	$167,885	$91,264	$67,170
Income taxes paid	$-	$13,032	$-
Non-cash investing and financing activities:			
Asset retirement obligations	$5,844	$274,148	$134,113

The accompanying notes to the consolidated financial statements

are an integral part of these statements.

F-6

MEXCO ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years Ended March 31, 2016, 2015 and 2014

1. Nature of Operations

Mexco Energy Corporation (a Colorado corporation) and its wholly owned subsidiaries, Forman Energy Corporation (a New York corporation), Southwest Texas Disposal Corporation (a Texas corporation) and TBO Oil & Gas, LLC (a Texas limited liability company) (collectively, the "Company") are engaged in the exploration, development and production of natural gas, crude oil, condensate and natural gas liquids ("NGLs"). Most of the Company's oil and gas interests are centered in West Texas; however, the Company owns producing properties and undeveloped acreage in thirteen states. Although most of the Company oil and gas interests are operated by others, the Company operates several properties in which it owns an interest.

2. Summary of Significant Accounting Policies

Principles of Consolidation. The consolidated financial statements include the accounts of Mexco Energy Corporation and its wholly owned subsidiaries. All significant intercompany balances and transactions associated with the consolidated operations have been eliminated.

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 informed judgments, estimates and assumptions that affect the reported amounts of assets and liabilities as of the date of the financial statements and affect the reported amounts of revenues and expenses during the reporting period. In addition, significant estimates are used in determining year end proved oil and gas reserves. Although management believes its estimates and assumptions are reasonable, actual results may differ materially from those estimates. The estimate of the Company's oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment of oil and gas properties, is the most significant of the estimates and assumptions that affect these reported results.

Cash and Cash Equivalents. The Company considers all highly liquid debt instruments purchased with maturities of three months or less and money market funds to be cash equivalents. The Company maintains cash in bank deposit accounts that may, at times, exceed federally insured limits. At March 31, 2016, the Company had the majority of its cash and cash equivalents with one financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk.

Accounts Receivable. Accounts receivable includes trade receivables from joint interest owners and oil and gas purchasers. Credit is extended based on an evaluation of a customer's financial condition and, generally, is uncollateralized. Accounts receivable under joint operating agreements have a right of offset against future oil and gas revenues if a producing well is completed. The collectability of receivables is assessed and an allowance is made for any doubtful accounts. The allowance for doubtful accounts is determined based on the Company's previous loss history. The Company has not experienced any significant credit losses. For the years ending March 31, 2016, 2015 and 2014, no allowance has been made for doubtful accounts.

Oil and Gas Properties. Oil and gas properties are accounted for using the full cost method of accounting. Under this method of accounting, the costs of unsuccessful, as well as successful, acquisition, exploration and development activities are capitalized as property and equipment. This includes any internal costs that are directly related to exploration and development activities but does not include any costs related to production, general corporate overhead or similar activities. The carrying amount of oil and gas properties also includes estimated asset retirement costs recorded based on the fair value of the asset retirement obligation ("ARO") when incurred. Generally, no gains or losses are recognized on the sale or disposition of oil and gas properties.

Excluded Costs. Oil and gas properties include costs that are excluded from capitalized costs being amortized. These amounts represent investments in unproved properties and major development projects. These costs are excluded until proved reserves are found or until it is determined that the costs are impaired. All costs excluded are reviewed at least quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the capitalized costs being amortized (the depreciation, depletion and amortization ("DD&A") pool). Impairments transferred to the DD&A pool increase the DD&A rate.

Ceiling Test. Under the full cost method of accounting, a ceiling test is performed each quarter. The full cost ceiling test is an impairment test to determine a limit, or ceiling, on the book value of oil and gas properties. That limit is basically the after tax present value of the future net cash flows from proved crude oil and natural gas reserves and using an average price over the prior 12-month period held flat for the life of production plus the lower of cost or fair market value of unproved properties. If net capitalized costs of crude oil and natural gas properties exceed the ceiling limit, the Company must charge the amount of the excess to earnings as an expense reflected in additional accumulated DD&A. This is called a “ceiling limitation write-down.” This impairment to our oil and gas properties does not impact cash flow from operating activities, but does reduce stockholders’ equity and reported earnings.

Depreciation, Depletion and Amortization. The depreciable base for oil and gas properties includes the sum of capitalized costs, net of accumulated DD&A, estimated future development costs and asset retirement costs not accrued in oil and gas properties, less costs excluded from amortization and salvage. The depreciable base of oil and gas properties is amortized using the unit-of-production method.

Asset Retirement Obligations. The Company has significant obligations to plug and abandon natural gas and crude oil wells and related equipment at the end of oil and gas production operations. The Company records the fair value of a liability for an ARO in the period in which it is incurred and a corresponding increase in the carrying amount of the related asset. Subsequently, the asset retirement costs included in the carrying amount of the related asset are allocated to expense using the units of production method. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense in the Consolidated Statements of Operations.

Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. The Company uses the present value of estimated cash flows related to the ARO to determine the fair value. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Income Taxes. The Company recognizes deferred tax assets and liabilities for future tax consequences of temporary differences between the carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates applicable to the years in which those differences are expected to be settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in net income in the period that includes the enactment date. Any interest and penalties are recorded as interest expense and general and administrative expense, respectively.

Other Property and Equipment. Provisions for depreciation of office furniture and equipment are computed on the straight-line method based on estimated useful lives of three to ten years.

Derivatives. The Company is required to recognize its derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized change in fair value on derivative instruments in the Consolidated Statements of Operations.

(Loss) Income Per Common Share. Basic net (loss) income per share is computed by dividing net (loss) income by the weighted average number of common shares outstanding during the period. Diluted net (loss) income per share assumes the exercise of all stock options having exercise prices less than the average market price of the common stock during the period using the treasury stock method and is computed by dividing net (loss) income by the weighted average number of common shares and dilutive potential common shares (stock options) outstanding during the period. In periods where losses are reported, the weighted-average number of common shares outstanding excludes potential common shares, because their inclusion would be anti-dilutive.

Revenue Recognition. Oil and gas sales and resulting receivables are recognized when the product is delivered to the purchaser and title has transferred. Sales are to credit-worthy energy purchasers with payments generally received within 60 days of transportation from the well site. The Company has historically had little, if any, uncollectible oil and gas receivables.

Gas Balancing. Gas imbalances are accounted for under the sales method whereby revenues are recognized based on production sold. A liability is recorded when excess takes of natural gas volumes exceed estimated remaining recoverable reserves (over produced). No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production (under produced). The Company does not have any significant gas imbalances.

Stock-based Compensation. The Company uses the Binomial option pricing model to estimate the fair value of stock based compensation expenses at grant date. This expense is recognized as compensation expense in its financial statements over the vesting period. The Company recognizes the fair value of stock-based compensation awards as wages in the Consolidated Statements of Operations based on a graded-vesting schedule over the vesting period.

Recent Accounting Pronouncements. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09, "Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting". The amendment is to simplify several aspects of the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in ASU No. 2016-09 are effective for interim and annual reporting periods beginning after December 15, 2016. The Company is currently assessing the impact of ASU No. 2016-09 on the consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, Topic 842 Leases, which requires companies to recognize a right of use asset and related liability on the balance sheet for the rights and obligations arising from leases with durations greater than 12 months. The standard is effective for fiscal years beginning after December 15, 2018, and interim periods thereafter. Early adoption is permitted. We are currently evaluating the effect the new guidance will have on our consolidated financial statements.

In January 2016, the FASB issued authoritative guidance that amends existing requirements on the classification and measurement of financial instruments. The standard principally affects accounting for equity investments and financial liabilities where the fair value option has been elected. The guidance is effective for fiscal periods after December 15, 2017, and interim periods thereafter. Early adoption of certain provisions is permitted. The Company is currently evaluating the effect the new guidance will have on its financial statements.

In November 2015, the FASB issued ASU No. 2015-17, Topic 740 Income Taxes: Balance Sheet Classification of Deferred Taxes which requires all deferred income tax liabilities and assets to be presented as noncurrent in a classified balance sheet. Currently, entities are required to separate deferred income tax liabilities and assets into current and noncurrent amounts in a classified balance sheet. The new standard will become effective for the Company beginning on April 1, 2017, with the option to early adopt, and can be applied either prospectively or retrospectively. The adoption of this guidance will have no impact on the Company’s results of operations or cash flows. The reclassification of amounts from current to noncurrent could affect the presentation of the Company’s balance sheet.

In February 2015, the FASB issued ASU No. 2015-02, Topic 810: Consolidation which amends the current consolidation guidance. ASU No. 2015-02 is effective for the Company as of April 1, 2016. The Company is assessing the standard update and does not believe there will be a significant impact on its consolidated financial statements.

In August 2014, the FASB issued ASU No. 2014-15, Subtopic 205-40: Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern which provides guidance on determining when and how reporting entities must disclose going-concern uncertainties in their financial statements. ASU No. 2014-15 is effective for the Company for the fiscal year ending March 31, 2017 and interim periods thereafter and early adoption is permitted. The Company does not expect the adoption of this ASU to have a material impact on its consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, Topic 606: Revenue from Contracts with Customers. This ASU provides guidance concerning the recognition and measurement of revenue from contracts with customers. The effective date for ASU 2014-09 was delayed through the issuance of ASU 2015-14, Revenue from Contracts with Customers – Deferral of the Effective Date, to annual and interim periods beginning in 2018 and is required to be adopted using either the retrospective or cumulative effect transition method, with early adoption permitted in 2017. Management is evaluating the effect, if any this pronouncement will have on our consolidated financial statements.

3. Fair Value of Financial Instruments.

Fair value as defined by authoritative literature is the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1 – Quoted prices in active markets for identical assets and liabilities.

Level 2 – Quoted prices in active markets for similar assets and liabilities, quoted prices for identical or similar instruments in markets that are not active and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 – Significant inputs to the valuation model are unobservable.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

The carrying amount reported in the accompanying consolidated balance sheets for cash and cash equivalents, accounts receivable and accounts payable approximates fair value because of the immediate or short-term maturity of these financial instruments.

The fair value amount reported in the accompanying consolidated balance sheets for long term debt approximates fair value because the actual interest rates do not significantly differ from current rates offered for instruments with similar characteristics and is deemed to use Level 2 inputs. See the Company's Note 4 on Credit Facility for further discussion.

The fair value of the Company's crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. The valuation of the Company's derivative instrument was deemed to use Level 2 inputs. See the Company's Note 7 on Derivatives for further discussion.

4. Credit Facility

The Company has a loan agreement with Bank of America, N.A. (the "Agreement"), which provided for a credit facility of $5,630,000 with no monthly commitment reductions and a borrowing base to be evaluated on July 30 and January 1 of each year or at any additional time in the Bank's discretion as of March 31, 2016. The borrowing base will be reset to the extent the Company sells or otherwise disposes of any of its oil and gas properties. The Company is required to pay 100% of such net proceeds to the lender resulting in a permanent reduction of the borrowing base. Subsequently, in April 2016, the Company sold some of its oil and gas properties for $60,000 and used these proceeds to pay on its line of credit, thus reducing its credit facility and borrowing base to $5,570,000. Amounts borrowed under the Agreement are collateralized by the common stock of the Company's wholly owned subsidiaries and substantially all of the Company's oil and gas properties.

The Agreement was renewed ten times with the tenth amendment effective as of March 31, 2016 with a maturity date of November 30, 2020. Under such renewal agreement, interest on the facility accrues at an annual rate equal to the British Bankers Association London Interbank Offered Rate ("BBA LIBOR") daily floating rate, plus an increased rate from 2.5 to 3.0 percentage points, which was 2.935% on March 31, 2016. Interest on the outstanding amount under the credit agreement is payable monthly. In addition, the Company no longer will pay an unused commitment fee in an amount equal to ½ to 1 percent (.5%) times the daily average of the unadvanced amount of the commitment. There was no availability of this line of credit at March 31, 2016. No principal payments are anticipated to be required through November 30, 2020.

The Agreement contains customary covenants for credit facilities of this type including limitations on change in control, disposition of assets, mergers and reorganizations. The Company is also obligated to meet certain financial covenants under the Agreement except that the tenth amendment replaces the tangible net worth test and requires minimum earnings before interest, taxes, depreciation and amortization (“EBITDA”) of $100,000 for the two fiscal quarters ending September 30, 2016, $300,000 for the three fiscal quarters ending December 31, 2016, $500,000 for the four fiscal quarters ending March 31, 2017 and $650,000 for each trailing fiscal quarter period thereafter and minimum interest coverage ratios (EBITDA/Interest Expense) of 1.25 to 1 for the fiscal quarter ending June 30, 2016 and 2.00 to 1.00 for each quarter thereafter. The Company is in compliance with all covenants as of March 31, 2016.

In addition, this Agreement prohibits the Company from paying cash dividends on its common stock. The Agreement does grant the Company permission to enter into hedge agreements however, it is under no obligation to do so.

The amended Agreement allows for up to $500,000 of the facility to be used for outstanding letters of credits. As of March 31, 2016, one letter of credit for $50,000, in lieu of plugging bond with the Texas Railroad Commission (“TRRC”) covering the properties the Company operates is outstanding under the facility. This letter of credit renews annually. The company will pay a fee in an amount equal to 1 percent (1.0%) per annum of the outstanding undrawn amount of each standby letter of credit, payable monthly in arrears, on the basis of the face amount outstanding on the day the fee is calculated.

The balance outstanding on the line of credit as of March 31, 2016 was $5,580,000 and as of June 15, 2016 was $5,520,000. The following table is a summary of activity on the Bank of America, N.A. line of credit for the year ended March 31, 2016:

	Principal
Balance at April 1, 2015:	$5,950,000
Borrowings	400,000
Repayments	(770,000)
Balance at March 31, 2016:	$5,580,000

5. Asset Retirement Obligations

The Company’s asset retirement obligations relate to the plugging of wells, the removal of facilities and equipment, and site restoration on oil and gas properties. The fair value of a liability for an ARO is recorded in the period in which it is incurred, discounted to its present value using the credit adjusted risk-free interest rate, and a corresponding amount capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted each period until the liability is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our oil and natural gas properties. The ARO is included on the consolidated balance sheets with the current portion being included in the accounts payable and accrued expenses.

The following table provides a rollforward of the asset retirement obligations for fiscal years ended March 31:

	2016	2015
Carrying amount of asset retirement obligations as of April 1	$1,240,216	$961,577
Liabilities incurred	5,844	274,148
Liabilities settled	(60,138)	(23,441)
Accretion expense	35,155	27,932
Carrying amount of asset retirement obligations as of March 31	1,221,077	1,240,216
Less: Current portion	10,000	10,000
Non-Current asset retirement obligation	$1,211,077	$1,230,216

F-11

6. Income Taxes

The Company files a consolidated federal income tax return and various state income tax returns. The amount of income taxes the Company records requires the interpretation of complex rules and regulations of federal and state taxing jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal and state income tax examinations by tax authorities for years prior to 2013.

Significant components of net deferred tax assets (liabilities) at March 31 are as follows:

	2016	2015
Deferred tax assets:		
Percentage depletion carryforwards	$1,718,721	$1,535,126
Deferred stock-based compensation	49,090	36,958
Asset retirement obligation	415,166	384,467
Net operating loss	1,493,914	720,308
Other	6,413	11,111
	3,683,304	2,687,970
Deferred tax liabilities:		
Excess financial accounting bases over tax bases of property and equipment	2,834,340	(3,348,840)
Deferred tax asset (liability)	$848,964	$(660,870)
Valuation allowance	(848,964)	-
Net deferred tax asset (liability)	$-	$(660,870)

As of March 31, 2016, the Company has a statutory depletion carryforward of approximately $5,000,000, which does not expire. At March 31, 2016, the Company had a net operating loss carryforward for regular income tax reporting purposes of approximately $6,600,000, which will begin expiring in 2029. The Company’s ability to use some of its net operating loss carryforwards and certain other tax attributes to reduce current and future U.S. federal taxable income is subject to limitations under the Internal Revenue Code.

A valuation allowance for deferred tax assets is required when it is more-likely-than-not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of this deferred tax asset depends on the Company's ability to generate sufficient taxable income in the future. Management believes it is more-likely-than- not that the net deferred tax asset will not be realized by future operating results.

The income tax provision consists of the following for years ended March 31, 2016, 2015 and 2014:

	2016	2015	2014
Current income tax expense	$-	$-	$6,500
Deferred income tax (benefit) expense	(660,870)	(197,499)	5,250
Total income tax provision:	$(660,870)	$(197,499)	$11,750
Effective tax rate	(14)%	(37)%	4%

The current income tax expense for fiscal year 2014 is the Company's alternative minimum tax that cannot offset with its alternative minimum tax net operating loss.

A reconciliation of the provision for income taxes to income taxes computed using the federal statutory rate for years ended March 31 follows:

	2016	2015	2014
Tax expense at federal statutory rate (1)	$(1,577,789)	$(183,085)	$106,374
Statutory depletion carryforward	(35,034)	(71,292)	(127,204)
Change in valuation allowance	848,964	-	-
Effect of graduated rates	64,585	12,221	(13,841)
Permanent differences	31,904	44,657	46,421
Other	6,500	-	-
Total income tax (benefit) expense	$(660,870)	$(197,499)	$11,750
Effective income tax rate	(14)%	(37)%	4%

(1) The federal statutory rate was 34% for fiscal years ending March 31, 2016, 2015 and 2014.

For the years ended March 31, 2016, 2015 and 2014, the Company did not have any uncertain tax positions.

A reconciliation of the beginning and ending balances of unrecognized tax benefits is as follows:

	2016	2015	2014
Unrecognized tax benefits at beginning of period	$679,000	$679,000	$677,000
Additions based on tax positions related to the current year	-	-	2,000
Changes to tax positions of prior years	-	-	-
Settlements	-	-	-
Expirations	-	-	-
Unrecognized tax benefits at end of period	$679,000	$679,000	$679,000

While the amount of unrecognized tax benefits may change in the next 12 months, the Company does not expect any change to have a significant impact on its results of operations. The recognition of the total amount of the unrecognized tax benefits would have an impact on the effective tax rate. If these unrecognized tax benefits are disallowed, the Company will be required to pay additional taxes.

Based on the material write-downs of the carrying value of our oil and natural gas properties for the year ending March 31, 2016, we are in a net deferred tax asset position at year end. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated was the cumulative loss incurred over the two-year period ending March 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or increased, or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as expected future growth.

7. Derivatives

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company’s fixed price swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company’s derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate (“NYMEX WTI”) pricing.

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the realized and unrealized changes in fair value in the consolidated statements of operations under the caption “Gain (loss) on derivative instruments.” The following summarizes the loss on derivative instruments included in the consolidated statements of operations for the years ended March 31, 2016, 2015 and 2014:

	2016	2015	2014
Unrealized loss on open non-hedge derivative instruments	$ -	$ -	$ (44,981)
Gain (loss) on settlement of non-hedge derivative instruments	-	102,069	(54,281)
Total gain (loss) on derivative instruments	$ -	$ 102,069	$ (99,262)

As of March 31, 2016 the Company does not have any open crude oil derivative positions with respect to future production.

8. Major Customers

Currently, the Company operates exclusively within the United States and its revenues and operating profit are derived from the oil and gas industry. Oil and gas production is sold to various purchasers and the receivables are unsecured. Historically, the Company has not experienced significant credit losses on its oil and gas accounts and management is of the opinion that significant credit risk does not exist. Management is of the opinion that the loss of any one purchaser would not have an adverse effect on the Company's ability to sell its oil and gas production.

In fiscal 2016, one customer accounted for 18% of the total oil and gas revenues and 14% of the total oil and gas accounts receivable and another customer accounted for 14% of the total oil and gas revenues and 18% of the total oil and gas accounts receivable. In fiscal 2015, one customer accounted for 17% of the total oil and gas revenues and 19% of the total oil and gas accounts receivable. In fiscal 2014, one customer accounted for 22% of the total oil and gas revenues and 25% of the total oil and gas accounts receivable.

9. Oil and Gas Costs

The costs related to the Company's oil and gas activities were incurred as follows for the year ended March 31:

	2016	2015	2014
Property acquisition costs:			
Proved	$-	$3,108,040	$785,144
Unproved	-	-	-
Exploration	-	15,472	9,641
Development	1,112,733	1,746,582	1,152,986
Capitalized asset retirement obligations	5,844	274,148	134,113
Total costs incurred for oil and gas properties	$1,118,577	$5,144,242	$2,081,884

The Company had the following aggregate capitalized costs relating to its oil and gas property activities at March 31:

	2016	2015	2014
Proved oil and gas properties	$40,365,197	$40,489,453	$35,386,751
Unproved oil and gas properties:			
subject to amortization	-	73,990	73,990

not subject to amortization	-	-	-
	40,365,197	40,563,443	35,460,741
Less accumulated DD&A	24,306,770	19,752,994	18,395,619
	$16,058,427	$20,810,449	$17,065,122

DD&A amounted to $2.45, $2.48 and $2.18 per mcfe of production for the years ended March 31, 2016, 2015 and 2014, respectively.

10. (Loss) Income Per Common Share

Due to a net loss for the year ended March 31, 2016 and 2015, the weighted average number of common shares outstanding excludes common stock equivalents because their inclusion would be anti-dilutive. For the year ended March 31, 2014, 35,000 options were excluded from the diluted net income per share calculations because the options are anti-dilutive. Anti-dilutive stock options have a weighted average exercise price of $5.98 at March 31, 2014.

The following is a reconciliation of the number of shares used in the calculation of basic income per share and diluted income per share for the periods ended March 31:

	2016	2015	2014
Net (loss) income	$(3,979,685)	$(340,986)	$301,113
Shares outstanding:			
Weighted avg. common shares outstanding – basic	2,037,266	2,038,250	2,036,950
Effect of the assumed exercise of dilutive stock options	-	-	5,234
Weighted avg. common shares outstanding – dilutive	2,037,266	2,038,250	2,042,184
(Loss) income per common share:			
Basic	$(1.95)	$(0.17)	$0.15
Diluted	$(1.95)	$(0.17)	$0.15

11. Stockholders' Equity

In June 2015, the Board of Directors authorized the use of up to $250,000 to repurchase shares of the Company's common stock for the treasury account. There were no shares of common stock repurchased for the treasury account during fiscal 2016. During the fiscal year ended March 31, 2015, the Company repurchased 1,000 shares for the treasury at an aggregate cost of $5,009. There were no shares of common stock repurchased for the treasury account during fiscal 2014.

12. Stock Options

In September 2009, the Company adopted the 2009 Employee Incentive Stock Plan (the "2009 Plan"). The 2009 Plan provides for the award of stock options up to 200,000 shares and includes option awards as well as stock awards. Option awards are granted with the restriction of requiring payment for the shares. Stock awards are granted without restrictions and without payment by the recipient. Neither option awards nor stock awards may exceed 25,000 shares granted to any one individual in any fiscal year. Stock options may be an incentive stock option or a nonqualified stock option. Options to purchase common stock under the plan are granted at the fair market value of the common stock at the date of grant, become exercisable to the extent of 25% of the shares optioned on each of four anniversaries of the date of grant, expire ten years from the date of grant and are subject to forfeiture if employment terminates. The 2009 Plan expires ten years from the date of adoption.

According to the Company's employee stock incentive plan, new shares will be issued upon the exercise of stock options and the Company can repurchase shares exercised under the plan. The plan also provides for the granting of stock awards. No stock awards were granted during fiscal 2016, 2015 and 2014.

The Company recognized compensation expense of $116,953, $153,386 and $152,448 in general and administrative expense in the Consolidated Statements of Operations for fiscal 2016, 2015 and 2014, respectively. The total cost related to non-vested awards not yet recognized at March 31, 2016 totals $78,653, which is expected to be recognized over a weighted average of 1.92 years.

The fair value of each stock option is estimated on the date of grant using the Binomial valuation model. Expected volatilities are based on historical volatility of the Company's stock over the contractual term of 120 months and other factors. The Company uses historical data to estimate option exercise and employee termination within the valuation model. The expected term of options granted is derived from the output of the option valuation model and represents the period of time that options granted are expected to be outstanding. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. As the Company has never declared dividends, no dividend yield is used in the calculation. Actual value realized, if any, is dependent on the future performance of the Company's common stock and overall stock market conditions. There is no assurance the value realized by an optionee will be at or near the value estimated by the Binomial model.

During the year ended March 31, 2016, no stock options were granted. During the year ended March 31, 2015, the Compensation Committee of the Board of Directors approved and the Company granted 40,000 stock options to officers and employees of the Company exercisable at $7.00 per share. During the year ended March 31, 2014, the Compensation Committee of the Board of Directors approved and the Company granted 35,000 stock options to officers and employees of the Company exercisable at $5.98 per share. These options are exercisable at a price not less than the fair market value of the stock at the date of grant, have an exercise period of ten years and generally vest over four years.

Included in the following table is a summary of the grant-date fair value of stock options granted and the related assumptions used in the Binomial models for stock options granted in fiscal 2016, 2015 and 2014. All such amounts represent the weighted average amounts for each period.

	For the year ended March 31,		
	2016	2015	2014
Grant-date fair value	-	$5.59	$4.75
Volatility factor	-	76.23%	77.01%
Dividend yield	-	-	-
Risk-free interest rate	-	2.52 %	1.74 %
Expected term (in years)	-	10	7

No forfeiture rate is assumed for stock options granted to directors or employees due to the forfeiture rate history for these types of awards. There were no stock options forfeited or expired during the years ended March 31, 2016, 2015 and 2014.

The following table is a summary of activity of stock options for the year ended March 31, 2016, 2015 and 2014:

	Number of Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contract Life in Years	Aggregate Intrinsic Value
Outstanding at April 1, 2013	80,000	$ 6.52	8.03	$-
Granted	35,000	5.98		
Exercised	(1,400)	6.29		
Forfeited or Expired	-	-		
Outstanding at March 31, 2014	113,600	$ 6.35	7.66	$154,062

Granted	40,000	7.00		
Exercised	-	-		
Forfeited or Expired	-	-		
Outstanding at March 31, 2015	153,600	$ 6.52	7.36	$-
Granted	-	-		
Exercised	-	-		
Forfeited or Expired	-	-		
Outstanding at March 31, 2016	153,600	$ 6.52	6.36	$-
Vested at March 31, 2016	106,100	$ 6.48	5.68	$-
Exercisable at March 31, 2016	106,100	$ 6.48	5.68	$-

Other information pertaining to option activity was as follows during the year ended March 31:

	2016	2015	2014
Weighted average grant-date fair value of stock options granted (per share)	$-	$5.59	$4.75
Total fair value of options vested	$154,338	$150,063	$108,500
Total intrinsic value of options exercised	$-	$-	$6,244

The following table summarizes information about options outstanding at March 31, 2016:

Range of Exercise Prices	Number of Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contract Life in Years	Aggregate Intrinsic Value
$5.98 – 6.25	45,000	$ 6.00		
6.26 – 6.50	28,600	6.29		
6.51 – 6.80	40,000	6.80		
6.81 – 7.00	40,000	7.00		
$5.98 – 7.00	153,600	$ 6.52	6.36	$ -

Outstanding options at March 31, 2015 expire between August 2020 and August 2024 and have exercise prices ranging from $5.98 to $7.00.

13. Related Party Transactions

Related party transactions for the fiscal year ended March 31, 2016 relate to shared office expenditures in addition to administrative and operating expenses paid on behalf of the principal stockholder. The total billed to and reimbursed by the stockholder for the years ended March 31, 2016, 2015 and 2014 were $92,723, $125,209 and $133,861, respectively.

14. Lease Commitments

The Company leases its principal office space. On April 1, 2013, the Company agreed to a three year lease, with an option to renew for an additional two years. On April 1, 2014, the Company agreed to a three year lease for an additional office space. In February 2016, the Company exercised its option to renew the 2013 lease. The following table summarizes future payments the Company is obligated to make based on the lease commitments in place as of March 31, 2016:

	Commitment Amount (1)
Fiscal Year 2017	$ 23,440

Fiscal Year 2018	$ 19,020

(1) The total commitment for the remainder of the leases is $60,939 which includes $18,479 billed to and reimbursed by the Company’s principal shareholder for his portion of the shared office space.

Lease expense for fiscal years ended March 31, 2016, 2015 and 2014 was $23,438, $23,442 and $19,020, respectively.

15. Oil and Gas Reserve Data (Unaudited)

The estimates of the Company’s proved oil and gas reserves, which are located entirely within the United States, were prepared in accordance with the guidelines established by the SEC. The estimates as of March 31, 2016, 2015, and 2014 are based on evaluations prepared by Joe C. Neal and Associates, Petroleum Consultants. Management emphasizes that reserve estimates are inherently imprecise and are expected to change as new information becomes available and as economic conditions in the industry change.

Proved reserves are estimated quantities of oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

The Company’s total estimated proved reserves at March 31, 2016 were approximately 2.051 million barrels of oil equivalent (“Boe”) of which 53% was oil and natural gas liquids and 47% was natural gas.

Changes in Proved Reserves:

	Oil (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:		
As of April 1, 2013	366,000	7,844,000
Revision of previous estimates	12,000	(1,404,000)
Purchase of minerals in place	50,000	18,000
Extensions and discoveries	101,000	163,000
Sales of minerals in place	-	-
Production	(27,000)	(362,000)
As of March 31, 2014	502,000	6,259,000
Revision of previous estimates	(90,000)	(665,000)
Purchase of minerals in place	43,000	795,000
Extensions and discoveries	235,000	269,000
Sales of minerals in place	-	-
Production	(30,000)	(369,000)
As of March 31, 2015	660,000	6,289,000
Revision of previous estimates	(13,000)	(736,000)
Purchase of minerals in place	-	-
Extensions and discoveries	479,000	665,000
Sales of minerals in place	(3,000)	(9,000)
Production	(39,000)	(408,000)
As of March 31, 2016	1,084,000	5,801,000

Proved developed reserves are those expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves (“PUD”) are proved reserves are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The downward revision of oil and natural gas is primarily the result of SEC rules which require such reserves to be developed within five years and because of the participation in one unsuccessful well. Reserves written off due to the five year limitation are primarily in the Haynesville field in Louisiana which are on leases held by production and are still in place to be developed in the future.

Summary of Proved Developed and Undeveloped Reserves as of March 31, 2016, 2015 and 2014:

	Oil (Bbls)	Natural Gas (Mcf)
Proved Developed Reserves:		
As of April 1, 2013	237,420	4,807,020
As of March 31, 2014	294,620	4,081,470
As of March 31, 2015	283,670	4,584,790

As of March 31, 2016	350,180	4,406,060
Proved Undeveloped Reserves:		
As of April 1, 2013	128,290	3,037,180
As of March 31, 2014	206,930	2,177,810
As of March 31, 2015	376,070	1,703,790
As of March 31, 2016	734,170	1,395,220

At March 31, 2016, the Company reported estimated PUDs of 5.8 bcfe, which accounted for 47% of its total estimated proved oil and gas reserves. This figure primarily consists of a projected 67 new wells (3.4 bcfe), 4 of which the Company operates. The 4 wells the Company operates (1.2 bcfe), will be drilled on existing acreage in the Goldsmith field where the Company currently operates 3 wells. The Company projects 4 operated wells will be drilled in fiscal 2019. Regarding the remaining 63 PUD locations operated by others (2.2 bcfe), 1 well is currently being drilled with plans for 14 wells to follow in 2017, 14 wells in 2018, 16 wells in 2019 and 18 wells in 2020.

As of March 31, 2016, 2015 and 2014 reserves were computed using the 12-month unweighted average of the first-day-of-the-month prices, in accordance with current SEC rules.

The following table discloses the Company's progress toward the conversion of PUDs during fiscal 2016.

Progress of Converting Proved Undeveloped Reserves:

	Oil & Natural Gas (Mcfe)	Future Development Costs
PUDs, beginning of year	3,960,232	$ 6,617,402
Revision of previous estimates	(1,441,324)	(2,778,279)
Conversions to PD reserves	(256,618)	(732,620)
Additional PUDs added	3,537,952	6,510,657
PUDs, end of year	5,800,242	$ 9,617,160

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average prices for 2016, 2015 and 2014 along with estimates of the operating costs, production taxes and future development costs necessary to produce such reserves. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Operating costs and production taxes are estimated based on current costs with respect to producing oil and natural gas properties. Future development costs including abandonment costs are based on the best estimate of such costs assuming current economic and operating conditions. The future cash flows estimated to be spent to develop the Company's share of proved undeveloped properties through March 31, 2021 are $9,617,160.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved, less applicable carryforwards.

The future net revenue information assumes no escalation of costs or prices, except for oil and natural gas sales made under terms of contracts which include fixed and determinable escalation. Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

The current reporting rules require that year end reserve calculations and future cash inflows be based on the 12-month average market prices for sales of oil and gas on the first calendar day of each month during the fiscal year discounted at 10% per year and assuming continuation of existing economic conditions. The average prices used for fiscal 2016 were $41.76 per bbl of oil and $1.998 per mcf of natural gas. The average prices used for fiscal 2015 were $74.84 per bbl of oil and $3.595 per mcf of natural gas. The average prices used for fiscal 2014 were $94.23 per bbl of oil and $3.67 per mcf of natural gas.

The standardized measure of discounted future net cash flows were computed by applying 12-month average prices for oil and gas (with consideration of price changes only to the extent provided by contractual arrangements in existence at year end) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on the year end statutory tax rates with consideration of future tax rates already legislated) to be incurred on pretax net cash flows less tax basis of the properties and available credits and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10%.

The basis for this table is the reserve studies prepared by an independent petroleum engineering consultant, which contain imprecise estimates of quantities and rates of production of reserves. Revisions of previous year estimates can have a significant impact on these results. Also, exploration costs in one year may lead to significant discoveries in later years and may significantly change previous estimates of proved reserves and their valuation. Therefore, the standardized measure of discounted future net cash flow is not necessarily indicative of the fair value of proved oil and gas properties.

The standardized measure of discounted future cash flows at March 31, 2016, 2015 and 2014, which represents the present value of estimated future cash flows using a discount rate of 10% a year, follows:

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves:

	March 31 2016	2015	2014
Future cash inflows	$57,318,000	$72,238,000	$70,252,000
Future production costs and taxes	(14,571,000)	(19,569,000)	(20,647,000)
Future development costs	(9,617,000)	(6,617,000)	(4,826,000)
Future income taxes	(4,569,000)	(9,254,000)	(9,801,000)
Future net cash flows	28,561,000	36,798,000	34,978,000
Annual 10% discount for estimated timing of cash flows	(14,663,000)	(17,860,000)	(15,649,000)
Standardized measure of discounted future net cash flows	$13,898,000	$18,938,000	$19,329,000

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

	March 31 2016	2015	2014
Sales of oil and gas produced, net of production costs	$(1,240,000)	$(2,036,000)	$(2,762,000)
Net changes in price and production costs	(12,510,000)	(4,066,000)	2,464,000
Changes in previously estimated development costs	3,701,000	2,627,000	270,000
Revisions of quantity estimates	(602,000)	(3,718,000)	(657,000)
Net change due to purchases and sales of minerals in place	(105,000)	2,777,000	1,332,000
Extensions and discoveries, less related costs	5,174,000	4,607,000	3,802,000
Net change in income taxes	2,539,000	654,000	(1,997,000)
Accretion of discount	2,370,000	2,474,000	1,779,000
Changes in timing of estimated cash flows and other	(4,367,000)	(3,710,000)	729,000
Changes in standardized measure	(5,040,000)	(391,000)	4,960,000
Standardized measure, beginning of year	18,938,000	19,329,000	14,369,000
Standardized measure, end of year	$13,898,000	$18,938,000	$19,329,000

16. Selected Quarterly Financial Data (Unaudited)

	FISCAL 2016 4th QTR	3rd QTR	2nd QTR	1st QTR
Oil and gas revenue	$432,723	$537,771	$720,874	$692,582

Operating loss	(390,005)	(2,549,990)	(1,094,279)	(435,481)
Net loss	(433,476)	(2,445,536)	(776,307)	(324,366)
Net loss income per share – basic	(0.21)	(1.20)	(0.38)	(0.16)
Net loss income per share – diluted	(0.21)	(1.20)	(0.38)	(0.16)

	FISCAL 2015			
	4th QTR	3rd QTR	2nd QTR	1st QTR
Oil and gas revenue	$551,894	$790,335	$987,942	$1,006,655
Operating (loss) profit	(412,332)	(240,224)	60,128	51,069
Net (loss) income	(270,975)	(175,321)	86,256	19,054
Net (loss) income per share – basic	(0.13)	(0.09)	0.04	0.01
Net (loss) income per share – diluted	(0.13)	(0.09)	0.04	0.01

17. Subsequent Events

In connection with Barnett Shale Fort Worth Basin royalties owned by the Company, the Company has been advised that settlement of a lawsuit for underpayment of royalties has been reached with the defendants, Chesapeake Energy Corporation and Total E&P USA resulting in an expected payment of $154,289 by September 1, 2016 of which $123,394 is payable in cash and a promissory note in the principal amount of $30,894, interest free, due in three years and payable by Chesapeake.

INDEX TO EXHIBITS

Exhibit Number	
3.1	Restated Articles of Incorporation of Mexco Energy Corporation filed as Exhibit 3.1 to the Company's Annual Report on Form 10-K dated June 24, 1998, and incorporated herein by reference.
3.2	Amended Bylaws of Mexco Energy Corporation as amended on September 13, 2011 filed as Exhibit 3.1 to the Company's Current Report on Form 8-K dated September 14, 2011, and incorporated herein by reference.
10.1	2009 Employee Incentive Stock Plan of Mexco Energy Corporation filed as Exhibit A to the Company's Proxy Statement on Form 14C dated July 15, 2009, and incorporated herein by reference.
10.2	Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.2 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.3	First Amendment to Loan Agreement dated December 28, 2009 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.3 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.4	Second Amendment to Loan Agreement dated March 1, 2010 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.4 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.5	Third Amendment to Loan Agreement dated September 30, 2010 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.5 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.6	Fourth Amendment to Loan Agreement dated October 22, 2010 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.6 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.7	Fifth Amendment to Loan Agreement dated December 28, 2011 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.7 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.8	Sixth Amendment to Loan Agreement dated October 22, 2012 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.8 to the Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.9	Seventh Amendment to Loan Agreement dated October 25, 2013 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.9 to the

Company's Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.

10.10	Eighth Amendment to Loan Agreement dated September 10, 2014 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.10 to the Company’s Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.11	Ninth Amendment to Loan Agreement dated February 13, 2015 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008 filed as Exhibit 10.11 to the Company’s Annual Report on Form 10-K dated June 25, 2015, and incorporated herein by reference.
10.12	Tenth Amendment to Loan Agreement dated March 31, 2016 to the Loan Agreement between Bank of America, N.A. and Mexco Energy Corporation dated December 31, 2008.
14.1	Code of Business Conduct and Ethics of Mexco Energy Corporation filed with the Company’s Quarterly Report on Form 10-Q filed on November 15, 2004, and incorporated herein by reference.
21.1	Subsidiaries of Mexco Energy Corporation
23.1	Consent of Grant Thornton LLP, Independent Registered Public Accounting Firm
23.2	Consent of Joe C. Neal & Associates, Independent Petroleum Engineers
31.1	Certification of the Chief Executive Officer of the Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of the Chief Financial Officer of the Company pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Report of Joe C. Neal & Associates, Independent Petroleum Engineer