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

FORM 10-K

[X] Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2012.

[ ] Transition report under Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ___________ to ___________

Commission File Number: 001-32624

FIELDPOINT PETROLEUM CORPORATION

(Name of Small Business Issuer in Its Charter)

Colorado	**84-0811034**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1703 Edelweiss Drive
Cedar Park, Texas 78613
(Address of Principal Executive Offices) (Zip Code)

(512) 250-8692
(Issuer's Telephone Number, Including Area Code)

Securities registered under Section 12(b) of the Exchange Act:
(None)

Securities registered under Section 12(g) of the Exchange Act:

Common Stock, $.01 Par Value
Title of Class

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

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

Note – Checking the box above will not relieve any registrant required to file reports pursuant to Section 13 or 15(d) of the Exchange Act from their obligations under those Sections.

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (check one):

Large accelerated filer [___] Accelerated filer [__]

Non-accelerated filer [___] (Do not check if a smaller reporting company) 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 and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was sold, or the average bid and asked price of such common equity, as of March 20, 2013, was $19,301,344.

The number of shares outstanding of the registrant's common stock as of March 20, 2013 is 8,064,836

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (*e.g.,* Part I, Part II, etc.) into which the document is incorporated: (1) Any annual report to security holders; (2) Any proxy or information statement; and (3) Any prospectus filed pursuant to Rule 424(b) or (c) under the Securities Act of 1933. The listed documents should be clearly described for identification purposes

Exhibits

See Part IV, Item 15.

PART I

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Form 10-K constitute “forward-looking statements’ within the meaning of the Private Securities Litigation Reform Act and Section 27A of the Securities Exchange Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this Form 10-K that address activities, events or developments that FieldPoint Petroleum Corp. and its subsidiaries (collectively, the "Company", “we”, “us”, “our” or “ours”) expects, projects, believes or anticipates will or may occur in the future, including such matters as oil and natural gas reserves, future drilling and operations, future production of oil and natural gas, future net cash flows, future capital expenditures and other such matters, are forward-looking statements. Such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others, the following: the volatility of oil and natural gas prices, the Company’s drilling and acquisition results, the Company’s ability to replace reserves, the availability of capital resources, the reliance upon estimates of proved reserves, operating hazards and uninsured risks, competition, government regulation, the ability of the Company to implement its business strategy and other factors referenced in this Form 10-K.

ITEM 1- BUSINESS

General

FieldPoint Petroleum Corporation, a Colorado corporation (the “Company”), was formed on March 11, 1980, to acquire and enhance mature oil and natural gas field production in the mid-continent and the Rocky Mountain regions. Since 1980, the Company had engaged in oil and natural gas operations and, in 1986, divested all oil and natural gas assets and operations. From December 1986, until its reverse acquisition on December 31, 1997, the Company did not engage in oil and natural gas operations. Since the reverse acquisition on December 31, 1997 the Company has been in the oil and natural gas exploration and production business.

Business Strategy

The Company’s business strategy is to continue to expand its reserve base and increase production and cash flow through the acquisition of producing oil and natural gas properties. Such acquisitions will be based on an analysis of the properties' current cash flow and the Company's ability to profit from the acquisition. The Company's ideal acquisition will include not only oil and natural gas production, but also leasehold and other working interests in exploration areas.

The Company will also seek to identify promising areas for the exploration of oil and natural gas through the use of outside consultants and the expertise of the Company. This identification will include collecting and analyzing geological and geophysical data for exploration areas. Once promising properties are identified, the Company will attempt to acquire the properties either for drilling oil and natural gas wells, using independent contractors for drilling operations, or for sale to third parties.

The Company recognizes that the ability to implement its business strategies is largely dependent on the ability to raise additional debt or equity capital to fund future acquisition, exploration, drilling and development activities. The Company's capital resources are discussed more thoroughly in Part II, Item 7, in Management's Discussion and Analysis.

Operations

As of December 31, 2012, the Company had varying ownership interest in 360 gross wells (100.33 net) located in five states. The Company operates 65 of the 360 wells; the other wells are operated by independent operators under contracts that are standard in the industry. It is a primary objective of the Company to operate some of the oil and natural gas properties in which it has an economic interest, and the Company will also partner with larger oil and natural gas companies to operate certain oil and natural gas properties in which the Company has an economic interest. The Company believes, with the responsibility and authority as operator, it is in a better position to control cost, safety, and timeliness of work as well as other critical factors affecting the economics of a well.

Market for Oil and Natural Gas

The demand for oil and natural gas is dependent upon a number of factors, including the availability of other domestic production, crude oil imports, the proximity and size of oil and natural gas pipelines in general, other transportation facilities, the marketing of competitive fuels, and general fluctuations in the supply and demand for oil and natural gas. The Company intends to sell all of its production to traditional industry purchasers, such as pipeline and crude oil companies, who have facilities to transport the oil and natural gas from the well site.

Competition

The oil and natural gas industry is highly competitive in all aspects. The Company competes with major oil companies, numerous independent oil and natural gas producers, individual proprietors, and investment programs. Many of these competitors possess financial and personnel resources substantially in excess of those which are available to the Company and may, therefore, be able to pay greater amounts for desirable leases and define, evaluate, bid for and purchase a greater number of potential producing prospects that the Company's own resources permit. The Company's ability to generate resources will depend not only on its ability to develop existing properties but also on its ability to identify and acquire proven and unproven acreage and prospects for further exploration.

Hydraulic Fracturing

Hydraulic fracturing is an important process and has been commonly used in the completion of unconventional oil and gas wells in shale and tight sand formations since the 1950s. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate oil and gas production. It is important to us because it provides access to oil and gas reserves that previously were uneconomical to produce.

We currently use hydraulic fracturing to complete both horizontal and vertical wells in the Permian Basin. We engage third parties to provide hydraulic fracturing services to us for completion of these wells. While hydraulic fracturing is not required to maintain our leasehold acreage that is currently held by production from existing wells, it will be required in the future to develop the proved non-producing and proved undeveloped reserves associated with this acreage. All of our proved non-producing and proved undeveloped reserves associated with future drilling, completion and recompletion projects will require hydraulic fracturing.

We believe we have followed, and intend to continue to follow, applicable industry standard practices and legal requirements for groundwater protection in our operations that are subject to supervision by state regulators.

These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by applicable state regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design is intended to prevent contact between the fracturing fluid and any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure-tested before perforating the new completion interval.

Injection rates and pressures are monitored at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. We believe we have adequate procedures in place to address abrupt changes to the injection pressure or annular pressure.

Texas regulations currently require disclosure of the components in the solutions used in hydraulic fracturing operations. Over 99% (by mass) of the ingredients we use in hydraulic fracturing are water and sand. The remainder of the ingredients are chemical additives that are managed and used in accordance with applicable requirements.

Hydraulic fracturing requires the use of a significant amount of water. Upon flowback of the water, we dispose of it in a way that we believe minimizes the impact to nearby surface water by disposing into approved disposal facilities or injection wells. Currently our primary sources of water are nonpotable and potable aquifers. We use water from on-lease water wells that we have drilled, and we purchase water from off-lease water wells. We also plan to reuse and recycle flow-back and produced water in 2013.

Operational Hazards and Insurance

The Company's operations are subject to the usual hazards incident to the drilling and production of oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pollution, releases of toxic gas and other environmental hazards and risks. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations.

The Company maintains insurance of various types to cover its operations. The Company's insurance does not cover every potential risk associated with the drilling and production of oil and natural gas. In particular, coverage is not obtainable for certain types of environmental hazards. The occurrence of a significant adverse event, the risks of which are not fully covered by insurance, could have a material adverse effect on the Company's financial condition and results of operations. Moreover, no assurance can be given that the Company will be able to maintain adequate insurance in the future at rates it considers reasonable.

Regulation

The oil and gas industry in the United States is subject to extensive regulation by federal, state and local authorities. At the federal level, various federal rules, regulations and procedures apply, including those issued by the U.S. Department of Interior, the U.S. Department of Transportation (the "DOT") (Office of Pipeline Safety) and the U.S. Environmental Protection Agency (the "EPA"). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Various remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines, penalties or other remedies that are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with federal, state and local rules, regulations and procedures, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations.

Transportation and Sale of Oil

Sales of crude oil and condensate are not currently regulated and are made at negotiated prices. Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by the Federal Energy Regulation Commission ("FERC") pursuant to the Interstate Commerce Act ("ICA"), Energy Policy Act of 1992 ("EPAct 1992"), and the rules and regulations promulgated under those laws. The ICA and its regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products, be just and reasonable and non-discriminatory and that such rates, terms and conditions of service be filed with FERC.

Intrastate oil pipeline transportation rates are also subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state-to-state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

The transportation of oil by truck is also subject to federal, state and local rules and regulations, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002. Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the DOT.

Transportation and Sale of Natural Gas and NGLs

FERC regulates interstate gas pipeline transportation rates and service conditions under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. FERC also regulates interstate NGL pipelines under various federal laws and regulations. Although FERC does not regulate oil and gas producers such as us, FERC's actions are intended to facilitate increased competition within all phases of the oil and gas industry and its regulation of third-party pipelines and facilities could indirectly affect our ability to transport or market our production. To date, FERC's policies have not materially affected our business or operations.

Regulation of Production

Oil, NGL and gas production is regulated under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The state in which we operate, Texas, has regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells, the regulation of spacing, and requirements for plugging and abandonment of wells. Also, Texas imposes a severance tax on production and sales of oil, NGLs and gas within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Laws and Regulations

In the United States, the exploration for and development of oil and gas and the drilling and operation of wells, fields and gathering systems are subject to extensive federal, state and local laws and regulations governing environmental protection as well as discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling begins;
- require the installation of expensive pollution controls or emissions monitoring equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, completion, production, transportation and processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, endangered species habitat, and other protected areas; and
- require remedial measures to mitigate and remediate pollution from historical and ongoing operations, such as the closure of waste pits and plugging of abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

Governmental authorities have the power to enforce compliance with environmental laws, regulations and permits, and violations are subject to injunction, as well as administrative, civil and criminal penalties. The effects of existing and future laws and regulations could have a material adverse impact on our business, financial condition and results of operations. The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretations of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our business, financial condition or results of operations. Moreover, accidental releases or spills and ground water contamination may occur in the course of our operations, and we may incur significant costs and liabilities as a result of such releases, spills or contamination, including any third-party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this will continue in the future.

The following is a summary of some of the existing environmental laws, rules and regulations that apply to our business operations.

Hazardous Substance Release

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), also known as the Superfund law, and comparable state statutes impose strict liability, and under certain circumstances, joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to strict, joint and several liabilities for the costs of investigating releases of hazardous substances, 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. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA.

Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced water and most of the other wastes associated with the exploration, development and production of oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could increase our operating expenses, which could have a material adverse effect on our business, financial condition and results of operations.

We currently own or lease properties that for many years have been used for oil and gas exploration, production and development activities. Although we used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on, under or from the properties owned or leased by us or on, under or from other locations where such wastes have been taken for disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons and wastes was not under our control. These properties and the materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes or contamination, or to perform remedial activities to prevent future contamination.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. In particular, on April 18, 2012, the EPA issued new regulations under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP"). The new regulations are designed to reduce volatile organic compound ("VOC") emissions from hydraulically-fractured natural gas wells, storage tanks and other equipment. The regulations established a phase-in period that extends until January 2015. During the phase-in period, owners and operators of hydraulically-fractured natural gas wells (wells drilled principally for the production of natural gas) must either flare their emissions or use so-called "green completion" technology. Green completions allow for the recovery of natural gas that formerly would have been vented or flared. After January 2015, all newly fractured natural gas wells must use green completion technology. We do not expect that the NSPS or NESHAP will have a material adverse effect on our business, financial condition or results of operations. However, any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements or use specific equipment or technologies to control emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We believe that we currently are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our current operations.

Greenhouse Gas Emissions

Congress has, from time-to-time, considered legislation to reduce emissions of GHGs. The current Congress is likely to continue to consider similar bills. Moreover, almost half of the states have already taken legal measures to reduce emissions of GHGs through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs or other mechanisms. Most cap-and-trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Many states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In response to its endangerment finding, the EPA has adopted two sets of rules regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions such as power plants or industrial facilities. The motor vehicle rule was finalized in April 2010 and became effective in January 2011, but it does not require immediate reductions in GHG emissions. In March 2012, the EPA proposed GHG emissions standards for fossil fuel-powered electric utility generating units that would require new plants to meet an output-based standard of 1,000 pounds of carbon dioxide equivalent per megawatt-hour. If the proposed regulation is adopted, it could have a significant impact on the electrical generation industry and may favor the use of natural gas over other fossil fuels such as coal in new plants. The EPA has also indicated that it will propose new GHG emissions standards for refineries, but specific proposed regulations are not expected to be issued until mid-2013.

In December 2010, the EPA enacted final rules on mandatory reporting of GHGs. In November and December 2011, the EPA published amendments to the rule containing technical and clarifying changes to certain GHG reporting requirements and a six-month extension for reporting GHG emissions from petroleum and natural gas industry sources. Under the amended rule, certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities are required to report their GHG emissions on an annual basis beginning on September 28, 2012. Our operations in the Permian Basin are subject to the EPA's mandatory reporting rules and we believe that we are in substantial compliance with such rules. We do not expect that the EPA's mandatory GHG reporting requirements will have a material adverse effect on our business, financial condition or results of operations.

The adoption of additional legislation or regulatory programs to monitor or reduce GHG emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory requirements. In addition, the EPA has stated that the data collected from GHG emissions reporting programs may be the basis for future regulatory action to establish substantive GHG emissions factors. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our future business, financial condition and results of operations.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act") and analogous state laws, impose restrictions and strict controls on the discharge of pollutants and fill material, including spills and leaks of oil and other substances into regulated waters, including wetlands. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA, an analogous state agency, or, in the case of fill material, the United States Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

In October 2011, the EPA announced that it intends to develop national standards for wastewater discharges produced by natural gas extraction from shale and coalbed methane formations. The EPA is expected to issue proposed regulations establishing wastewater discharge standards for coalbed methane wastewater in 2013 and for shale gas wastewater in 2014. For shale gas wastewater, the EPA will consider imposing pre-treatment standards for discharges to a wastewater treatment facility. Produced and other flowback water from our current operations in the Permian Basin is typically re-injected into underground formations that do not contain potable water. To the extent that re-injection is not available for our operations and discharge to wastewater treatment facilities is required, new standards from the EPA could increase the cost of disposing wastewater in connection with our operations.

The Safe Drinking Water Act, Groundwater Protection and the Underground Injection Control Program

The federal Safe Drinking Water Act ("SDWA") and the Underground Injection Control program (the "UIC program") promulgated under the SDWA and state programs regulate the drilling and operation of salt water disposal wells. The EPA has delegated administration of the UIC program in Texas to the Railroad Commission of Texas ("RRC"). Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and gas drilling, production and related operations may result in fines, penalties and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages and bodily injury.

Hydraulic Fracturing

Hydraulic fracturing is the subject of significant focus among some environmentalists, regulators and the general public. Concerns over potential hazards associated with the use of hydraulic fracturing and its impact on the environment have been raised at all levels, including federal, state and local, as well as internationally. There have been claims that hydraulic fracturing may contaminate groundwater, reduce air quality or cause earthquakes. Hydraulic fracturing requires the use and disposal of water, and public concern has been growing over its possible effects on drinking water supplies, as well as the adequacy of water supply.

The Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. In the past, legislation has been introduced in, but not passed by, Congress that would amend the SDWA to repeal this exemption. If similar legislation were enacted, it could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. Future federal legislation could also require the reporting and public disclosure of chemical additives used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemical additives used in the fracturing process could adversely affect groundwater. If federal legislation regulating hydraulic fracturing is adopted in the future, it could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

In 2010, the EPA asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the UIC program by posting a requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. Industry groups filed suit challenging the EPA's decision as a "final agency action" and, therefore, a violation of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. In February 2012, the EPA and industry reached a settlement under which the EPA will modify the informal policy posted on its website concerning the need for permits under the UIC program. However, the settlement does not reflect agreement on the issue of hydraulic fracturing regulation under the SDWA, and the EPA's continued assertion of its regulatory authority under the SDWA could result in extensive requirements that could cause additional costs and delays in the hydraulic fracturing process.

In addition to the above actions of the EPA, certain members of the Congress have called upon (i) the Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; (ii) the Securities and Exchange Commission (the "SEC") to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale by means of hydraulic fracturing; and (iii) the Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The SEC has issued subpoenas to certain shale gas producers requesting information on proved reserve estimates from shale gas wells and the actual productivity of producing shale gas wells. The media has also reported that the New York attorney general has issued subpoenas to certain oil and gas companies seeking information regarding shale gas wells.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has also begun a study of the potential environmental impacts of hydraulic fracturing. The EPA issued a progress report in December 2012, and final results are expected in 2014. In addition, the U.S. Department of Energy conducted an investigation into practices the agency could recommend to better protect the environment from using hydraulic fracturing. The Shale Gas Subcommittee of the Secretary of Energy Advisory Board released its "90-day" report on August 18, 2011, and its final report on November 18, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. These ongoing or proposed investigations and studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in hydraulic fracturing. For example, pursuant to legislation adopted by the State of Texas in June 2011, the RRC enacted a rule in December 2011, requiring disclosure to the RRC and the public of certain information regarding additives, chemical ingredients, concentrations and water volumes used in hydraulic fracturing. In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and hydraulic fracturing in particular.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, it could become more difficult or costly for us to drill and produce oil and gas from shale and tight sands formations and become easier for third parties opposing hydraulic fracturing to initiate legal proceedings. In addition, if hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to delays, additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and higher costs. These new laws or regulations could cause us to incur substantial delays or suspensions of operations and compliance costs and could have a material adverse effect on our business, financial condition and results of operations.

Compliance

We believe that we are in substantial compliance with all existing environmental laws and regulations that apply to our current operations and that our ongoing compliance with existing requirements will not have a material adverse effect on our business, financial condition or results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the year ended

December 31, 2012. In addition, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital or operating expenditures during 2013. However, the passage of additional or more stringent laws or regulations in the future could have a negative effect on our business, financial condition and results of operations, including our ability to develop our undeveloped acreage.

Threatened and Endangered Species, Migratory Birds and Natural Resources

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, the Migratory Bird Treaty Act, the Clean Water Act 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. Where takings of, or harm to, species or damages to wetlands, habitat or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties.

OSHA and Other Laws and Regulations

We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

Administration

Office Facilities – The office space for the Company's executive offices at 1703 Edelweiss Drive, Cedar Park, Texas 78613, is currently provided by the President at a cost of $2,500 per month as of December 31, 2012.

Employees – As of March 20, 2013, the Company had 4 employees, and the Company considers its relationship with its employees satisfactory.

ITEM 1A – RISK FACTORS.

Oil and gas operations are risky.

We compete in the areas of oil and gas exploration, production, development and transportation with other companies, many of which may have substantially larger financial and other resources. The nature of the oil and gas business also involves a variety of risks, including the risks of operating hazards such as fires, explosions, cratering, blow-outs, and encountering formations with abnormal pressures, the occurrence of any of which could result in losses to us. We maintain insurance against some, but not all, of these risks in amounts that management believes to be reasonable in accordance with customary industry practices. The occurrence of a significant event, however, that is not fully insured could have a material adverse effect on our financial position.

A substantial decrease in oil and natural gas prices would have a material impact on us.

Our future financial condition and results of operations are dependent upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future. This price volatility will also affect our common stock price. We cannot predict oil and natural gas prices and prices may decline in the future. The following factors have an influence on oil and natural gas prices, including but not limited to:

* changes in the supply of and demand for oil and natural gas;
* storage availability;
* weather conditions;
* market uncertainty;
* domestic and foreign governmental regulations;
* the availability and cost of alternative fuel sources;
* the domestic and foreign supply of oil and natural gas;
* the price of foreign oil and natural gas;
* refining capacity;
* political conditions in oil and natural gas producing regions, including the Middle East; and
* overall economic conditions.

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

Our business will depend on transportation facilities owned by others.

The marketability of our gas production will depend in part on the availability, proximity, and capacity of pipeline systems owned by third parties. Although we will have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce, gather, and transport oil and natural gas.

Market conditions could cause us to incur losses on our transportation contracts.

Gas transportation contracts that we may enter into in the future may require us to transport minimum volumes of natural gas. If we ship smaller volumes, we may be liable for the shortfall. Unforeseen events, including production problems or substantial decreases in the price of natural gas, could cause us to ship less than the required volumes, resulting in losses on these contracts.

Our actual production, revenues and expenditures related to our reserves are likely to differ from our estimates of our proved reserves. We may experience production that is less than estimated and drilling costs that are greater than estimated in our reserve reports. These differences may be material.

The proved oil, NGL and gas reserves data included in this report are estimates. Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil, NGL and gas reserves and of future net cash flows necessarily depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other similar producing areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil, NGL and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserves estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil, NGL and gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future oil, NGL and gas prices.

Estimates of proved undeveloped reserves are even less reliable than estimates of proved developed reserves. Furthermore, different reserve engineers may make different estimates of reserves and future net revenues based on the same available data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

Estimating our reserves future net cash flows is difficult to do with any certainty.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, the precision of the engineering and geological interpretation, and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows, and present value are based on various assumptions, including those prescribed by the Securities and Exchange Commission, and are inherently imprecise. There is no assurance that our present oil and gas wells will continue to produce at current or anticipated rates of production, or that production rates achieved in early periods can be maintained. Actual future production, cash flows, taxes, operating expenses, and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. A reduction in oil and natural gas prices not only would reduce the value of any proved reserves, but also might reduce the amount of oil and natural gas that could be economically produced, thereby reducing the quantity of reserves. Our reserves and future cash flows may be subject to revisions, based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, operating costs, and other factors. Downward revisions of our reserves could have an adverse affect on our financial condition and operating results.

Acquiring interests in other properties involves substantial risks.

We evaluate and acquire interests in oil and natural gas properties which in management's judgment will provide attractive investment opportunities for the addition of production and oil and gas reserves. To acquire producing properties or undeveloped exploratory acreage will require an assessment of a number of factors including:

* Value of the properties and likelihood of future production;
* Recoverable reserves;
* Operating costs;
* Potential environmental and other liabilities;
* Drilling and production difficulties; and
* Other factors beyond our control

Such assessments will necessarily be inexact and uncertain. Because of our limited financial resources, we may not be able to evaluate properties in a manner that is consistent with industry practices. Such reviews, therefore, may not reveal all existing or potential problems, nor will they permit us to become sufficiently familiar with such properties to assess fully the deficiencies or benefits.

Operational risks in our business are numerous and could materially impact us.

Oil and natural gas drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. We can make no assurance that wells in which we have an interest will be productive or that we will recover all or any portion of investment costs.

Our operations are also subject to hazards and risks inherent in drilling for and producing and transporting oil and natural gas, including, but not limited to, such hazards as:

* Fires;
* Explosions;
* Blowouts;
* Encountering formations with abnormal pressures;
* Spills
* Natural disasters;
* Pipeline ruptures;
* Cratering

If any of these events occur in our operations, we could experience substantial losses due to:

* injury or loss of life;
* severe damage to or destruction of property, natural resources and equipment;
* pollution or other environmental damage;
* clean-up responsibilities;
* regulatory investigation and penalties; and
* other losses resulting in suspension of our operations.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above with a general liability limit of $1 million. We do not maintain insurance for damages arising out of exposure to radioactive material. Even in the case of risks against which we are insured, our policies are subject to limitations and exceptions that could cause us to be unprotected against some or all of the risk. The occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations.

We must comply with environmental regulations.

Exploratory and other oil and natural gas wells must be operated in compliance with complex and changing environmental laws and regulations adopted by federal, state and local government authorities. The implementation of new, or the modification of existing, laws and regulations could have a material adverse affect on properties in which we may have an interest. Discharge of oil, natural gas, water, or other pollutants to the oil, soil, or water may give rise to significant liabilities to government and third parties and may require us to incur substantial cost of remediation. We may be required to agree to indemnify sellers of properties purchased against certain liabilities for environmental claims associated with those properties. We can give no assurance that existing environmental laws or regulations, as currently interpreted, or as they may be reinterpreted in the future, or future laws or regulations will not materially adversely affect our results of operations and financial conditions.

Environmental liabilities could adversely affect our business

In the event of a release of oil, natural gas, or other pollutants from our operations into the environment, we could incur liability for personal injuries, property damage, cleanup costs, and governmental fines. We could potentially discharge these materials into the environment in any of the following ways:

* from a well or drilling equipment at a drill site;
* leakage from gathering systems, pipelines, transportation facilities and storage tanks;
* damage to oil and natural gas wells resulting from accidents during normal operations; and
* blowouts, cratering, and explosions.

In addition, because we may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in our production of oil and gas and lower returns on our capital investments.

Bills were introduced in the previous U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used in fracturing fluids by the oil and natural gas industry under the federal Safe Drinking Water Act ("SDWA") and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act ("EPCRA") or other authority. Hydraulic fracturing is an important and commonly used process in the completion of unconventional oil and natural gas wells in shale and tight sand formations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us for many of the wells that we drill and operate. Sponsors of such bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies, surface waters, and other natural resources, and threaten health and safety. In addition, the EPA has announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health and the EPA issued a draft study plan on hydraulic fracturing. Certain states have also considered or imposed reporting obligations relating to the use of hydraulic fracturing techniques.

Additional legislation or regulation could make it easier for 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. There has also been increasing public controversy regarding hydraulic fracturing with regard to 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 in Texas and other states implicating hydraulic fracturing practices.

Legislation, regulation, litigation and enforcement actions at the federal, state or local level that restrict the provision of hydraulic fracturing services could limit the availability and raise the cost of such services, delay completion of new wells and production of our oil and gas, lower our return on capital expenditures and have a material adverse impact on our business, financial condition, results of operations and cash flows and quantities of oil and gas reserves that may be economically produced.

Changes in tax laws may adversely affect our results of operations and cash flows.

President Obama's Proposed Fiscal Year 2013 Budget includes proposed legislation that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to:

- repeal of the percentage depletion allowance for oil and gas properties;
- elimination of current deductions for intangible drilling costs;
- elimination of the domestic manufacturing deduction for oil and gas companies; and
- 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 any legislation as a result of these proposals or any other similar changes in

U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

Competition in the oil and natural gas industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with major integrated oil and gas companies and independent oil and gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have operated for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Climate change legislation or regulations regulating emissions of GHGs and VOCs could result in increased operating costs and reduced demand for the oil and gas we produce.

Both houses of Congress have actively considered legislation to reduce emissions of GHGs, and some states have already taken measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap-and-trade programs require either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances are expected to escalate significantly in cost over time.

In addition, in December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow 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. The EPA has also issued final regulations under the NSPS and NESHAP designed to reduce VOCs. The adoption of legislation or regulatory programs to reduce GHG or VOC emissions could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce GHG or VOC emissions could have a material adverse effect on our business, financial condition and results of operations.

Governmental regulations can hinder production.

Domestic oil and natural gas exploration, production and sales are extensively regulated at both the federal and state levels. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, have legal authority to issue, and have issued, rules and regulations affecting the oil and natural gas industry which often are difficult and costly to comply with and which carry substantial penalties for noncompliance. State statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states where we operate also have statutes and regulations governing conservation matters, including the unitization or pooling of properties. Our operations are also subject to numerous laws and regulations governing plugging and abandonment, discharging materials into the environment or otherwise relating to environmental protection. The heavy regulatory burden on the oil and natural gas industry increases its costs of doing business and consequently affects its profitability. Changes in the laws, rules or regulations, or the interpretation thereof, could have a materially adverse effect on our financial condition or results of operation.

Minority or royalty interest purchases do not allow us to control production completely.

We sometimes acquire less than the controlling working interest in oil and natural gas properties. In such cases, it is likely that these properties would not be operated by us. When we do not have controlling interest, the operator or the other co-owners might take actions we do not agree with and possibly increase costs or reduce production income in ways we do not agree with.

Environmental regulations can hinder production.

Oil and natural gas activities can result in liability under federal, state and local environmental regulations for activities involving, among other things, water pollution and hazardous waste transport, storage, and disposal. Such liability can attach not only to the operator of record of the well, but also to other parties that may be deemed to be current or prior operators or owners of the wells or the equipment involved. We have inspections performed on our properties to assure environmental law compliance, but inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken.

Government regulations could increase our operating costs

Oil and natural gas operations are subject to extensive federal, state and local laws and regulations relating to the exploration for, and development, production and transportation of, oil and natural gas, as well as safety matters, which may changed from time to time in response to economic conditions. Matters subject to regulation by federal, state and local authorities include:

* Permits for drilling operations;
* The production and disposal of water;
* Reports concerning operations;
* Unitization and pooling of properties;
* Road and pipeline construction;
* The spacing of wells;
* Taxation;
* Production rates;
* The conservation of oil and natural gas; and
* Drilling bonds.

Many jurisdictions have at various times imposed limitations on the production of oil and natural gas by restricting the rate of flow for oil and natural gas wells below their actual capacity to produce. During the past few years there has been a significant amount of discussion by legislators and the presidential administration concerning a variety of energy tax proposals. There can be no certainty that any such measure will be passed or what its effect will be on oil and natural gas prices if it is passed. In addition, many states have raised state taxes on energy sources and additional increases may occur, although there can be no certainty of the effect that increases in state energy taxes would have on oil and natural gas prices. Although we believe it is in substantial compliance with applicable environmental and other government laws and regulations, there can be no assurance that significant costs for compliance will not be incurred in the future.

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

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. We do not intend to declare or pay any cash dividends 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 operating results, financial condition, current and anticipated cash needs, and other factors. Moreover, since the issuance of the Warrants in March 2012 we reclassified $6,895,361 of retained earnings to additional paid-in capital, there may be no capacity for the Company to declare a cash dividend in the near future.

ITEM 1B. – UNRESOLVED STAFF COMMENTS.

None.

ITEM 2-PROPERTIES

Principal Oil and Natural Gas Interests

Block A-49 and Block 6 Field, Andrews County, Texas is a producing oil field located in Andrews, Texas. The Company owns a 74%-100% working interest in five producing oil wells and three injection wells producing out of the Devonian and Ellenburger formations at an approximate depth of 7,000 to 9,000 feet.

Spraberry Trend, Midland County, Texas is a producing oil and natural gas field located 6 miles east of Midland, Texas. The Company owns a 6% to 15% working interest in five oil and natural gas wells producing out of the Spraberry formation at a depth of approximately 7,000 feet.

Flying M Field, Lea County, New Mexico is a producing oil and natural gas field located outside of Hobbs, New Mexico. The Company owns a 39.25% working interest in two oil and natural gas wells producing out of the ABO formation at a depth of approximately 8,300 feet.

Sulimar Field, Chaves County, New Mexico is a producing oil field located 35 miles north east of Artesia, New Mexico. The Company has a 100% working interest in one oil well producing out of the Queen formation at a depth of approximately 1,800 feet.

Apache Field, Caddo County, Oklahoma is a waterflood project producing from the Viola/Bromide formation. The Apache Bromide Unit is located approximately 5 miles west of the town of Apache and

25 miles north of Lawton, Oklahoma. The Company has a 25.23% working interest in the unit which consists of 11 producing oil wells and 9 water injection wells.

North Bilbrey Field, Lea County, New Mexico is a producing natural gas field located outside of Hobbs, New Mexico. The Company owns a 50% working interest in the North Bilbrey #7 federal well producing out of the Atoka formation at approximately 13,000 feet.

Longwood Field, Caddo Parish, Louisiana is a producing natural gas field located north of Greenwood, Louisiana. The Company owns a 12.22% working interest in two natural gas wells producing out of the Cotton Valley formation at a depth of approximately 7,800 feet.

Lusk Field, Lea County, New Mexico is a producing oil and natural gas field located outside of Hobbs, New Mexico. The Company owns an 87.5%-100% working interest in two oil and natural gas wells producing out of the Bonesprings and Yates formations in section 15 at depth ranging from approximately 3,400 feet to approximately 10,000 feet and a 43.75% working interest in two wells drilled and producing out of the Bonesprings formation. 14.06% working interest in one oil and natural gas well producing out of the Wolfcamp formation in section 14. The Company also owns an 87.5% working interest in one water disposal well.

Loving North Morrow Field, Eddy County, New Mexico is a producing natural gas field located 2 miles west of Loving, New Mexico and 12 miles south east of Carlsbad, New Mexico. The Company owns a 4.3% - 12% working interest in three natural gas wells producing out of the Morrow formation from a depth of approximately 12,300 feet to 12,450 feet.

Chickasha Field, Grady County, Oklahoma is a waterflood project producing from the Medrano Sand. The Rush Springs Medrano Unit is located approximately 65 miles southwest of Oklahoma City, Oklahoma. The Company has a 20.64% working interest in the unit which consists of 21 producing oil and natural gas wells and 11 water injection wells.

West Allen Field, Pontotoc County, Oklahoma is a producing oil and natural gas field located approximately 100 miles south of Oklahoma City, Oklahoma. The Company has a working interest in 52 leases or a total of 224 wells, the leases have multiple wellbores and the Company has plans to participate in the future recompletion of behind pipe zones.

Giddings Field, Fayette County, Texas is in the Austin Chalk field located in various counties surrounding the city of Giddings, Texas. In February 1998, the Company acquired a 97% working interest in the Shade lease. The lease currently has three producing oil and natural gas wells. Oil and natural gas are produced from the Austin chalk formation. The Company will evaluate whether additional reserves can be developed by use of horizontal well technology.

Big Muddy Field, Converse County, Wyoming is a producing oilfield located approximately 30 miles south of Casper, Wyoming. The Company owns a 100% working interest in the Elkhorn and J.C. Kinney lease which consists of three oil wells producing out of the Wallcreek and Dakota formations at depths ranging from approximately 3,200 feet to approximately 4,000 feet.

Serbin Field, Lee and Bastrop Counties Texas is an oil and natural gas field located approximately 50 miles east of Austin and 100 miles west of Houston. The Company has a working interest in 50 producing oil and natural gas wells. Oil and natural gas are produced from the Taylor Sand at depths ranging from approximately 5,300 feet to approximately 5,600 feet; it is a 46-gravity oil sand.

Tuleta West Field, Bee County Texas, is a natural gas field located North of Corpus Christi, Texas. The Company owns a 5% working interest in one natural gas well producing from the Wilcox formation at a depth of approximately 12,000 feet.

Production

The table below sets forth oil and natural gas production from the Company's net interest in producing properties for each of its last two fiscal years.

		Oil (bbl)		Gas (mcf)	
Production by State		2012	2011	2012	2011
Louisiana		33	32	9,200	9,286
New Mexico		49,897	16,568	118,564	86,228
Oklahoma		33,160	30,194	27,610	19,102
Texas		14,955	19,395	24,724	28,526
Wyoming		6,240	3,206	-	-
	TOTAL	104,285	69,395	180,098	143,142

The Company's oil and natural gas production is sold on the spot market and the Company does not have any production that is subject to firm commitment contracts. During the year end December 31, 2012, purchases by three customers, Cimarex Energy Co.,Sunoco and Enterprise Crude represented more than 10% of total Company revenues. During the year ended December 31, 2011, purchases by each of four customers, Sunoco, Enterprise Crude, Ram Energy Resources, and Quantum Resources represented more than 10% of total Company revenues. None of these customers, or any other customers of the Company, has a firm sales agreement with the Company. The Company believes that it would be able to locate alternate customers in the event of the loss of one or all of these customers.

Productive Wells

The table below sets forth certain information regarding the Company's ownership, as of December 31, 2012, of productive wells in the areas indicated.

Productive Wells

	Oil		Gas	
State	Gross[1]	Net[2]	Gross[1]	Net[2]
Louisiana	-	-	2	.24
New Mexico	8	2.91	4	.61
Oklahoma	228	51.13	37	4.59
Texas	70	34.12	8	4.15
Wyoming	3	2.58	-	-
Total	309	90.74	51	9.59

[1] A gross well or acre is a well or acre in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.
[2] A net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions thereof.

Drilling Activity

The tables below set forth certain information regarding the number of productive and dry exploratory and development wells drilled for the fiscal year ended December 31, 2012.

	Exploratory Wells		Development Wells	
State	**Productive**	**Dry**	**Productive**	**Dry**
Louisiana	--	--	--	--
New Mexico	--	--	1	--
Oklahoma	--	--	--	--
Texas	--	--	--	--
Wyoming	--	--	--	--
Total	--	--	1	--

Reserves

Estimated Proved Reserves/Developed and Undeveloped Reserves: The following tables set forth the estimated proved developed and proved undeveloped oil and gas reserves of FieldPoint for the years ended December 31, 2012 and 2011. See Notes 11 and 12 to the Consolidated Financial Statements and the following discussion.

Estimated Proved Reserves

Proved Reserves	Oil (Bbls)	Gas (Mcf)
Estimated quantity, January 1, 2011	1,168,955	2,638,656
Revisions of previous estimates	(20,872)	(430,706)
Extensions and discoveries	123,526	204,740
Sales of reserves	(1,950)	-
Production	(69,395)	(143,142)
Estimated quantity, December 31, 2011	1,200,264	2,269,548
Revisions of previous estimates	13,854	48,955
Extensions and discoveries	115,093	209,930
Sales of reserves	-	-
Production	(104,285)	(180,098)
Estimated quantity, December 31, 2012	1,224,926	2,348,335

Proved Developed and Undeveloped Reserves

	Developed	Undeveloped	Total
Oil (Bbls)			
December 31, 2012	983,900	241,026	1,224,926
December 31, 2011	980,341	219,923	1,200,264
Gas (Mcf)			
December 31, 2012	1,898,705	449,630	2,348,335
December 31, 2011	1,922,181	347,367	2,269,548

Proved Undeveloped Reserves

As of December 31, 2012, we had 315,964 BOE of proved undeveloped ("PUD") reserves, which is an increase of 38,147 BOE or 14%, compared with 277,818 BOE of PUD reserves at December 31, 2011. As a percent of our total proved reserves, our PUD reserves increased from 18% in 2011 to 20% in 2012 due to our ongoing development of our East Lusk field.

The following table summarizes the changes in our PUD reserves during 2012.

	Oil (Bbls)	Gas (Mcf)	Total (BOE)
Balance – December 31, 2011	219,923	347,367	277,818
Extensions and discoveries	113,678	253,344	155,902
Revisions to previous estimates	(23,120)	(31,801)	(28,421)
Conversion to proved developed reserves	(69,455)	(119,280)	(89,335)
Balance – December 31, 2012	241,026	449,630	315,964

The following table sets forth our PUD reserves converted to proved developed reserves during 2012 and 2011 and the net investment required to convert PUD reserves to proved developed reserves during the year.

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
Year Ended December 31,	Oil (Bbls)	Gas (Mcf)	Total (BOE)	
2011	70,900	121,760	91,193	$ 4,200,000
2012	69,455	119,280	89,335	3,000,000
Total	140,355	241,040	180,528	$ 7,200,000

The following table sets forth our estimated future development costs relating to the development of PUD reserves:

Year Ended December 31,	Estimated Future Development Costs
2013	$ 2,625,000
2014	20,000
2015	1,877,000
2016	165,000
2017	-
Total	$ 4,687,000

We monitor fluctuations in commodity prices, drilling and completion costs, operating expenses and drilling success to determine adjustments to our drilling and development program. We plan to drill the East Lusk Federal Well #3 starting mid-year 2013. Based on current expectations for cash flows, commodity prices and operating costs and expenses, all PUD reserves are scheduled to be drilled before the end of 2017.

Preparation of Proved Reserves Estimates

Internal Controls Over Preparation of Proved Reserves Estimates

Our policies regarding internal controls over the recording of reserve estimates require reserve estimates to be in compliance with SEC rules, regulations and guidance and prepared in accordance with generally accepted petroleum engineering principles. Our proved oil and natural gas reserves as of December 31, 2012 and December 31, 2011 have been estimated by Fletcher Lewis Engineering, Inc., and PGH Engineers. These independent consultants are responsible for overseeing the preparation of our reserve estimates and for internal compliance of our reserve estimates with SEC rules, regulations and generally accepted petroleum engineering principles. Ray Reaves, President and CEO, provides company data (such as well ownership interests, oil and gas prices, production volumes and well operating costs) to consulting petroleum engineers and is the primary Company employee responsible for reviewing their use of our data and estimation of our reserves. Mr. Reaves, who has over twenty years of experience as a chief executive officer in the oil and gas exploration industry, provides our consulting petroleum engineers with technical data (such as well logs, geological information and well histories). Mr. Reaves also reviews the preliminary reserve estimates and the financial inputs in the estimates. Mr. Reaves calculates the disclosed changes in reserve estimates and the disclosed changes in the Standardized Measure relating to proved oil and gas reserves.

As defined in the Securities and Exchange Commission Rules, proved reserves are the estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include considerations of changes in existing prices provided only by contractual arrangements but not on escalations based on future conditions. Reservoirs are considered proved if economic production is supported by either actual production or conclusive formation tests. Reserves which can be produced economically through application of improved recovery techniques, such as fluid injections, are included in the “proved” classification when successful testing by a pilot project, or the operations of an installed program in the reservoir, provide support for the engineering analysis on which the project or program was based. Due to the inherent uncertainties and the limited nature of reservoir data, such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimate. Revisions result primarily from new information obtained from development drilling and production history and from changes in economic factors.

For information concerning the standardized measure of discounted future net cash flows, estimated future net cash flows and present values of such cash flows attributable to our proved oil and gas reserves as well as other reserve information, see Notes 11 and 12 to the Consolidated Financial Statements.

Technologies Used in Preparation of Proved Reserves Estimates

Estimates of reserves were prepared by the use of standard geological and engineering methods generally accepted by the petroleum industry. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

When applicable, the volumetric method was used to estimate the original oil in place, or OOIP, and the original gas in place, or OGIP. Structure and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation. When adequate data were available and when circumstances justified, material balance and other engineering methods were used to estimate OOIP or OGIP.

Estimates of ultimate recovery were obtained after applying recovery factors to OOIP or OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors. An analysis of reservoir performance, including production rate, reservoir pressure and gas-oil ratio behavior, was used in the estimation of reserves.

Because our proved reserves are located in depletion-type reservoirs and reservoirs whose performance demonstrates a reliable decline in producing-rate trends, reserves were also estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-declining curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses or leases as appropriate.

Reserves Sensitivity Analysis

As permitted by the recently adopted SEC regulations, we have elected not to undertake a sensitivity analysis of our reserves estimates.

Oil and Gas Reserves Reported to Other Agencies: We did not file any estimates of total proved net oil or gas reserves with, or include such information in reports to, any federal authority or agency during the fiscal year ended December 31, 2012, or subsequently thereafter.

Title Examinations: Oil and Gas: As is customary in the oil and gas industry, we perform only a perfunctory title examination at the time of acquisition of undeveloped properties. Prior to the commencement of drilling, in most cases, and in any event where we are the Operator, a thorough title examination is conducted and significant defects remedied before proceeding with operations. We believe that the title to our properties is generally acceptable to a reasonably prudent operator in the oil and gas industry. The properties we own are subject to royalty, overriding royalty and other interests customary in the industry, liens incidental to operating agreements, current taxes and other burdens, minor encumbrances, easements and restrictions. We do not believe that any of these burdens materially detract from the value of the properties or will materially interfere with our business.

We have purchased producing properties on which no updated title opinion was prepared. In some, but not all, cases, we have retained third party certified petroleum landmen to review title.

Acreage

The following tables set forth the gross and net acres of developed and undeveloped oil and natural gas leases in which the Company had working interest and royalty interest as of December 31, 2012. The category of "Undeveloped Acreage" in the table includes leasehold interest that already may have been classified as containing proved undeveloped reserves.

	Developed		Undeveloped	
State	**Gross [1]**	**Net [2]**	**Gross [1]**	**Net [2]**
Louisiana	320	78	-	-
New Mexico	2,400	896	480	262
Oklahoma	8,826	1,300	200	19
Texas	3,263	1,200	1,360	1,000
Wyoming	560	268	2,306	1,880
Total	15,369	3,742	4,346	3,161

[1] A gross well or acre is a well or acre in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.
[2] A net well or acre is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions thereof.

ITEM 3-LEGAL PROCEEDINGS

None.

ITEM 4-SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5-MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Since September 20, 2005 the Company's common stock has been traded and listed on the NYSE MKT, LLC, formerly the NYSE Amex and before that the NYSE Alternext and formerly the American Stock Exchange, under the symbol "FPP." Prior to September 20, 2005, the Company's common stock was listed on the OTC bulletin board under the symbol FPPC. The following sets forth the high and low closing prices of our common stock on the NYSE MKT, LLC for the periods shown.

FISCAL 2011	CLOSING PRICE	
	HIGH	LOW
First Quarter	5.48	3.61
Second Quarter	5.00	2.88
Third Quarter	3.33	2.01
Fourth Quarter	4.97	1.72
FISCAL 2012		
	HIGH	LOW
First Quarter	6.00	3.81
Second Quarter	4.69	3.15
Third Quarter	5.21	3.60
Fourth Quarter	4.80	3.42

At March 20, 2013, the approximate number of shareholders of record was 319. The Company has not paid any cash dividends on its common stock and does not expect to do so in the foreseeable future.

EQUITY COMPENSATION PLAN INFORMATION

	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuances under equity compensation plans (excluding securities reflected in column
Equity compensation plans approved by security holders	-	-	-
Equity compensation plans not approved by security holders	-	-	-
Total	-	-	-

ITEM 6 SELECTED FINANCIAL DATA

We have set forth below certain selected financial data. The information has been derived from the financial statements, financial information and notes thereto included elsewhere in this report.

	Years Ended December 31,	
	2012	**2011**
Statements of Operations Data:		
Total revenues	$10,402,889	$ 7,235,860
Operating expenses	7,314,380	6,072,903
Net income	2,112,263	602,564
Basic earnings per share	$ 0.26	$ 0.08
Shares used in computing basic earnings per share	8,006,959	8,015,878
Diluted earnings per share	$ 0.25	$ 0.08
Shares used in computing diluted earnings per share	8,452,429	8,015,878

	December 31,	
Balance Sheet Data:	**2012**	**2011**
Working capital	$ 2,109,552	$ 1,019,901
Total assets	23,135,430	21,362,889
Total liabilities	11,953,965	12,487,276
Stockholders' equity	11,181,465	8,875,613

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

The following discussion should be read in conjunction with the Company's Financial Statements, and respective notes thereto, included elsewhere herein. The information below should not be construed to imply that the results discussed herein will necessarily continue into the future or that any conclusion reached herein will necessarily be indicative of actual operating results in the future. Such discussion represents only the best present assessment of the management of FieldPoint Petroleum Corporation.

Overview

FieldPoint Petroleum Corporation derives its revenues from its operating activities including sales of oil and natural gas and operating oil and natural gas properties. The Company's capital for investment in producing oil and natural gas properties has been provided by cash flow from operating activities and from bank financing. The Company categorizes its operating expenses into the categories of production expenses and other expenses.

Results of Operations

	Years Ended December 31, 2012	Years Ended December 31, 2011
Revenues:		
Oil sales	$ 9,457,292	$ 6,364,308
Natural gas sales	783,336	745,017
Total	$ 10,240,628	$ 7,109,325
Sales volumes:		
Oil (Bbls)	104,285	69,395
Natural gas (Mcf)	180,098	143,142
Total (BOE)	134,301	93,252
Average sales prices		
Oil ($/Bbl)	$ 90.69	$ 91.71
Natural gas ($/Mcf)	4.35	5.20
Total ($/BOE)	$ 76.25	$ 76.24
Costs and expenses ($/BOE)		
Lease operating	$ 16.39	$ 20.78
Production taxes	8.38	5.47
Depletion and depreciation	15.58	11.99
Impairment of oil and natural gas properties	1.52	14.56
Accretion of discount on asset retirement obligations	0.68	0.90
General and administrative	11.92	11.43
Total	$ 54.47	$ 65.13

Revenues
Oil and natural gas sales revenues increased by $3,131,303 or 44%, primarily due to increased production. Oil sales increased $3,093,000 due to increased production that contributed $3,200,000 to the increase in oil sales revenues offset by $107,000 due to slightly lower prices. Oil sales volumes increased by 50%, primarily due to production from the two new wells in New Mexico completed in December, 2011 and September 2012. Natural gas sales increased $38,000 or 5%, due primarily to increased natural gas production in 2012. Oil and natural gas prices have been volatile during 2012 and the Company expects this to continue. FieldPoint's oil and natural gas sales revenue will be highly dependent on commodity prices in 2013.

Lease Operating Expenses
Lease operating expenses increased by $263,811 or 14% due to a combination of increased sales volumes and decreased cost. Cost decreased by $4.39 per barrel equivalent (BOE) or 21% in 2012 as compared to 2011. Increased sales volumes contributed approximately $853,000 to the increase in costs and was offset approximately $589,000 in lower costs as a result of reduced remedial repairs from the prior year. Many of FieldPoint's properties are mature and bear high operating expense which could result in increased operating costs in the future.

Production Taxes
Production taxes increased $615,269 or 121%, primarily the result of increased oil and natural gas sales revenues as discussed above and an increase in the tax paid to the Apache Tribe. Production taxes amounted to approximately 11% of oil and natural gas sales revenue during 2012 and 7.2% during 2011. The increase was a result of an unanticipated charge of previous years' taxes paid to the Apache Tribe in 2012. Management expects production taxes to range between 7% and 9% of oil and natural gas sales revenue.

Depletion and Depreciation
Depletion and depreciation expense increased by $974,000 or 87%. The increase in depletion and depreciation was primarily due to depletion on two new wells completed in September 2011 and December 2012.

Impairment of Oil and Natural Gas Properties
Impairment of $204,190 was recorded during the year ended December 31, 2012 on the Loving property. During the year ended December 31, 2011 the Company recorded impairment of $390,000 on the Loving property, $9,741 on the Stauss property, and $837,827 on the South Vacuum property for a total of $1,237,568 on our proved oil and natural gas properties. Additionally, the Company recorded impairment on unproved properties totaling $119,771 in 2011.

General and Administrative Expense
General and administrative expenses increased $534,546 or 50% primarily due to increases in compensation expense and professional services fees. Significant components of general and administrative expenses include personnel-related costs and professional services fees. Management expects FieldPoint's general and administrative expenses to remain relatively comparable to 2012 next year.

Other Income (Expense)
Interest expense increased in 2012 by $25,325 or 11%. During the year ended December 31, 2012 the Company realized a $254,151 gain on commodity derivatives. Also in 2012, the Company sold their interest in the South Vacuum property at a gain of $204,000.

Liquidity and Capital Resources

Cash flow provided by operating activities was approximately $3.33 million for the year ended December 31, 2012, compared to $3.98 million for the year ended December 31, 2011. The decrease in cash flow from operating activities was primarily due to a decrease in accounts payable and impairment offset by changes in net income and increased depletion and deferred income tax expenses.

In 2012 FieldPoint used its operating cash flow along with cash on hand to fund $4.4 million of development of oil and natural gas properties. The Company sold its interest in the South Vacuum property for $204,000. These were the primary components of cash used in investing activites in 2012. Cash provided by financing activities for 2012 was $193,589. The Company sold 60,761 shares of common stock for $257,358 and related expenses were $63,769, pursuant to an At Market Issuance Sales Agreement with MLV & Co., LLC. FieldPoint used its operating cash flow along with cash on hand in 2011 to fund $2.6 million of development of oil and natural gas properties and to repurchase an aggregate of 94,000 shares of FieldPoint common stock for a total purchase price of $358,550. The sale of the Whisler property provided $68,330 in cash flow during 2011. These were the principal components of cash used in investing and financing activities in 2011. The repurchases of stock were undertaken pursuant to a stock buy-back program approved by the Board of Directors. Further, management evaluates the market price and trading volume of FieldPoint's common stock and may repurchase shares if capital is available and management believes that such repurchase would be advantageous to the Company and its stockholders.

Capital Requirements

Management believes the Company will be able to meet its current operating needs through internally generated cash from operations and borrowings under the Company's revolving credit facility. As of December 31, 2012, the Company had working capital of approximately $2.1 million and approximately $4.3 million borrowing capacity under its line of credit based on a borrowing base of $11 million. The borrowing base is subject to redetermination based on the value of proved reserves, and could be increased or decreased during 2013.

Although the Company had no significant commitments for capital expenditures at December 31, 2012, management anticipates continued investments in oil and natural gas properties during 2013. If bank credit is not available, FieldPoint may not be able to continue to invest in strategic oil and natural gas properties. Management cannot predict how oil and natural gas prices will fluctuate during 2013 and what effect they will ultimately have on the Company, but management believes that the Company will be able to generate sufficient cash from operations to service its bank debt and provide for maintaining current production of its oil and natural gas properties. The timing of most capital expenditures is relatively discretionary. Therefore, the Company can plan expenditures to coincide with available funds in order to minimize business risks. As of December 31, 2012, the Company had approximately $210,518 of capital items in accounts payable that will be paid from working capital.

Contractual Obligations and Commitments

We have contractual obligations and commitments that affect our consolidated results of operations, financial condition and liquidity. The following table is a summary of our significant cash contractual obligations:

	Obligation Due in Period				
Cash Contractual Obligations	2013	2014	2015	Thereafter	Total
	(in thousands)				
Credit facility (secured)	$ -	$ -	$ 6,740	$ -	$ 6,740
Interest on credit facility	264	264	197	-	725
Total	$ 264	$ 264	6,937	$ -	$ 7,465

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our accounting policies are described in Note 1 of Notes to Consolidated Financial Statements in Item 8. We prepare our Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP"), which require us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates. We consider the following policies to be most critical in understanding the judgments that are involved in preparing our financial statements and the uncertainties that could impact our results of operations, financial condition and cash flows.

Successful Efforts Method of Accounting

We account for our exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production amortization rate. A gain or loss is recognized for all other sales of producing properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and natural gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial which will result in additional exploration expenses when incurred.

Reserve Estimates

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and 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 natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to an extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected therefrom may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and natural gas properties and/or the rate of depletion of the oil and natural gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Impairment of Oil and Natural Gas Properties

We review our oil and natural gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of our oil and natural gas properties and compare such future cash flows to the carrying amount of our oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to their fair value. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. There were $204,190 of impairments on our proved oil and natural gas properties in 2012 and $1,237,568 of impairments of oil and natural gas properties in 2011.

Reporting Requirements

Because our common stock is publicly traded, we are subject to certain rules and regulations of federal, state and financial market exchange entities charges with the protection of investors and the oversight of companies whose securities are publicly traded. These entities, including the SEC and the NYSE MKT, LLC, have issued requirements and regulations and are currently developing additional regulations and requirements in response to laws, enacted by Congress, most notably the Sarbanes-Oxley Act 2002 and SEC reporting regulations which became effective January 1, 2010. Our compliance with current rules requires the commitment of significant managerial resources. We concluded that our internal control over financial reporting were effective as of December 31, 2012.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We periodically enter into certain commodity price risk management transactions to manage our exposure to oil and natural gas price volatility. These transactions may take the form of futures contracts, swaps or options. All data relating to our derivative positions is presented in accordance with requirements of authoritative accounting guidance. Unrealized gains and losses related to the change in fair value of derivative contracts that qualify and are designated as cash flow hedges are recorded as other comprehensive income or loss and such amounts are reclassified to oil and natural gas sales revenues as the associated production occurs. Derivative contracts that do not qualify for hedge accounting treatment are recorded as derivative assets and liabilities at fair value in the consolidated balance sheet, and the associated unrealized gains and losses are recorded as current expense or income in the consolidated statement of operations. While such derivative contracts do not qualify for hedge accounting, management believes these contracts can be utilized as an effective component of commodity price risk management activities. At December 31, 2012 and December 31, 2011, there were no open positions. We did have derivative transactions during 2012 and 2011.

ITEM 8 FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
FieldPoint Petroleum Corporation and Subsidiaries
Cedar Park, Texas

We have audited the accompanying consolidated balance sheets of FieldPoint Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated 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. The Company is not required to have, nor were we engaged to perform, an audit of its 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 FieldPoint Petroleum Corporation and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the years then ended, in conformity with U.S. generally accepted accounting principles.

/s/Hein & Associates LLP

Dallas, Texas
March 20, 2013

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

ASSETS

	DECEMBER 31, 2012	DECEMBER 31, 2011
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,408,075	$ 2,037,593
Certificates of deposit	44,702	44,469
Accounts receivable:		
Oil and natural gas sales	1,193,495	1,007,025
Joint interest billings, less allowance for doubtful accounts of approximately $174,000 and $99,000 respectively	229,406	209,209
Income taxes receivable	196,555	332,134
Deferred income tax asset-current	171,000	58,000
Prepaid expenses and other current assets	42,349	121,745
Total current assets	3,285,582	3,810,175
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	32,210,252	27,616,928
Other equipment	52,113	52,113
Less accumulated depletion and depreciation	(12,412,517)	(10,116,327)
Net property and equipment	19,849,848	17,552,714
Total assets	$ 23,135,430	$ 21,362,889

LIABILITIES AND STOCKHOLDERS' EQUITY

	2012	2011
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 889,796	$ 2,506,145
Oil and natural gas revenues payable	286,234	259,129
Asset retirement obligation – current	-	25,000
Total current liabilities	1,176,030	2,790,274
LINE OF CREDIT	6,740,000	6,740,000
DEFERRED INCOME TAXES	2,442,000	1,467,000
ASSET RETIREMENT OBLIGATION	1,595,935	1,490,002
Total liabilities	11,953,965	12,487,276
COMMITMENTS AND CONTINGENCIES (Notes 9 and 10)		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value, 75,000,000 shares authorized; 8,970,936 and 8,910,175 shares issued, respectively; and 8,043,936 and 7,983,175 outstanding, respectively	89,709	89,101
Additional paid-in capital	11,661,922	4,573,580
Retained earnings	1,396,726	6,179,824
Treasury stock, 927,000 shares, each period, at cost	(1,966,892)	(1,966,892)
Total stockholders' equity	11,181,465	8,875,613
Total liabilities and stockholders' equity	$ 23,135,430	$ 21,362,889

See accompanying notes to these consolidated financial statements.

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	DECEMBER 31, 2012	DECEMBER 31, 2011
REVENUE:		
Oil and natural gas sales	$ 10,240,628	$ 7,109,325
Well operational and pumping fees	68,265	68,265
Disposal fees	93,996	58,270
Total revenue	10,402,889	7,235,860
COSTS AND EXPENSES:		
Lease operating	3,326,624	2,447,544
Depletion and depreciation	2,092,000	1,118,000
Impairment of oil and natural gas properties	204,190	1,357,339
Accretion of discount on asset retirement obligations	91,000	84,000
General and administrative	1,600,566	1,066,020
Total costs and expenses	7,314,380	6,072,903
OPERATING INCOME	3,088,509	1,162,957
OTHER INCOME (EXPENSE):		
Interest income	2,389	5,054
Interest expense	(264,120)	(238,795)
Realized gain on commodity derivatives	254,151	-
Gain (loss) on sale of oil and natural gas property	204,000	(10,670)
Miscellaneous	1,334	71,018
Total other income (expense)	197,754	(173,393)
INCOME BEFORE INCOME TAXES	3,286,263	989,564
INCOME TAX PROVISION – current	(312,000)	(12,000)
INCOME TAX PROVISION – deferred	(862,000)	(375,000)
TOTAL INCOME TAX PROVISION	(1,174,000)	(387,000)
NET INCOME	$ 2,112,263	$ 602,564
EARNINGS PER SHARE:		
BASIC	$ 0.26	$ 0.08
DILUTED	$ 0.25	$ 0.08
WEIGHTED AVERAGE SHARES OUTSTANDING:		
Basic	8,006,959	8,015,878
Diluted	8,452,429	8,015,878

See accompanying notes to these consolidated financial statements.