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

FORM 10-K

☒ **Annual report under Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2011.

☐ **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 ☒ 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 ☒ No ☐

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

Indicate by check mark whether the registrant 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 ☒ 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 ☒

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates 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, 2012, was $25,685,717.

The number of shares outstanding of the registrant’s common stock as of March 20, 2012 is 7,983,175

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 had not engaged in oil and natural gas operations.

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, 2011, the Company had varying ownership interest in 361 gross productive wells (101.52 net) located in five states. The Company operates 67 of the 361 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.

Environmental Matters and Government Regulations

The Company's operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Such matters have not had a material effect on operations of the Company to date, but the Company cannot predict whether such matters will have any material effect on its capital expenditures, earnings or competitive position in the future.

The production and sale of oil and natural gas are currently subject to extensive regulations of both federal and state authorities. At the federal level, there are price regulations, windfall profits tax, and income tax laws. At the state level, there are severance taxes, proration of production, spacing of wells, prevention and clean-up of pollution and permits to drill and produce oil and natural gas. Although compliance with their laws and regulations has not had a material adverse effect on the Company's operations, the Company cannot predict whether its future operations will be adversely effected thereby.

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.

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, 2011.

Employees – As of March 20, 2012, 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.

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 2012 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.

The oil and natural gas industry is highly competitive.

The oil and gas industry is highly competitive in all its phases. Competition is particularly intense with respect to the acquisition of desirable producing properties, the acquisition of oil and gas prospects suitable for enhanced production efforts, and the hiring of experienced personnel. Our competitors in oil and gas acquisition, development, and production include the major oil companies in addition to numerous independent oil and natural gas companies, individual proprietors and drilling programs.

Many of our competitors possess and employ financial and personnel resources far greater than those which are available to us. They may be able to pay more for desirable producing properties and prospects and to define, evaluate, bid for, and purchase a greater number of producing properties and prospects than we can. We must compete against these larger companies for suitable producing properties and prospects, to generate future oil and natural gas reserves.

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 dividends and do not anticipate paying any 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 will reclassify all 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 one well drillied 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 52 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	**2011**	**2010**	**2011**	**2010**
Louisiana	32	23	9,286	10,381
New Mexico	16,568	17,854	86,228	89,334
Oklahoma	30,194	30,401	19,102	18,984
Texas	19,395	22,720	28,526	33,619
Wyoming	3,206	6,576	—	—
TOTAL	69,395	77,574	143,142	152,318

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, 2011, purchases by four customers, Ram Energy Resources, Inc., Quantum Resources Co., Sunoco and Enterprise Crude represented more than 10% of total Company revenues. During the year ended December 31, 2010, purchases by each of four customers, Sunoco, Enterprise Crude, ConocoPhillips, and Ram Energy 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, 2011, of productive wells in the areas indicated.

Productive Wells

State	Oil Gross[(1)]	Oil Net[(2)]	Gas Gross[(1)]	Gas Net[(2)]
Louisiana	—	—	2	.24
New Mexico	7	2.55	4	.61
Oklahoma	228	51.13	37	4.59
Texas	72	35.67	8	4.15
Wyoming	3	2.58	—	—
Total	310	91.93	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, 2011. The Company drilled no wells in 2010.

State	Exploratory Wells Productive	Exploratory Wells Dry	Development Wells Productive	Development Wells 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, 2011 and 2010. See Notes 9 and 10 to the Consolidated Financial Statements and the following discussion.

Estimated Proved Reserves

Proved Reserves	Oil (Bbls)	Gas (Mcf)
Estimated quantity, January 1, 2010	1,203,183	3,458,707
Revisions of previous estimates	43,346	(667,733)
Production	(77,574)	(152,318)
Estimated quantity, December 31, 2010	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

Proved Developed and Undeveloped Reserves

	Developed	Undeveloped	Total
Oil (Bbls)			
December 31, 2011	980,341	219,923	1,200,264
December 31, 2010	885,658	283,297	1,168,955
Gas (Mcf)			
December 31, 2011	1,922,181	347,367	2,269,548
December 31, 2010	2,181,689	456,967	2,638,656

Proved Undeveloped Reserves

During fiscal year ended December 31, 2011, the Company's proved undeveloped reserves decreased by approximately 81,640 BOE. This decreased resulted primarily from the reclass of a certain PUD location that was drilled and moved to proved producing, and from the removal of the South Vacuum gas field.

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, 2011 and December 31, 2010 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 Note 10 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, 2011, 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, 2011. 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	2,080	756	800	348
Oklahoma	8,826	1,300	200	19
Texas	3,343	1,201	1,360	1,000
Wyoming	560	268	2,306	1,880
Total	15,129	3,603	4,666	3,247

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.

Subsequent Events

In February 2012, the Company was advised by the well operator that the South Vacuum 35 #3 well in the South Vacuum Field in Lea County, New Mexico will be plugged and abandoned. This resulted in an impairment charge of approximately $838,000 which was recorded in the fourth quarter of 2011.

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 Amex, formerly 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 Amex for the periods shown.

	CLOSING PRICE	
FISCAL 2010	**HIGH**	**LOW**
First Quarter	2.50	1.93
Second Quarter	3.20	2.11
Third Quarter	3.90	2.63
Fourth Quarter	4.55	2.73
FISCAL 2011	**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

At March 20, 2012, the approximate number of shareholders of record was 131. The Company has not paid any cash dividends on its common stock and does not expect to do so in the foreseeable future.

Recent Sales of Unregistered Securities

Issuer Purchases of Equity Securities

Period	(a) Total number of shares (or units) purchased	(b) Average price paid per share (or unit)	(c) Total number of shares (or units) purchased as part of publicly announced plans or programs	(d) Maximum number (or approximate dollar value) of shares (or units) that may yet be purchased under the plans or programs
October 01, 2011 to December 31, 2011	14,000	$ 2.51	14,000	$ 0
Total	14,000		14,000	

On March 24, 2011, the Board of Directors authorized the Company to repurchase additional shares of its common stock at an aggregate cost not to exceed $250,000 each. Stock purchases were made from time to time in the open market or in privately-negotiated transactions, if and when management determined to effect purchases. All stock repurchases were subject to the requirements of Rule 10b-18 under the Exchange Act.

EQUITY COMPENSATION PLAN INFORMATION

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuances under equity compensation plans (excluding securities reflected in column (a)) (c)
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, 2011	Years Ended December 31, 2010
Statements of Operations Data:		
Total revenues	$ 7,235,860	$ 7,008,783
Operating expenses	6,072,903	5,571,076
Net income	602,564	787,470
Basic earnings per share	$ 0.08	$ 0.10
Shares used in computing basic earnings per share	8,015,878	8,200,541
Diluted earnings per share	$ 0.08	$ 0.10
Shares used in computing diluted earnings per share	8,015,878	8,200,541

	December 31, 2011	December 31, 2010
Balance Sheet Data:		
Working capital	$ 1,019,901	$ 2,604,029
Total assets	21,362,889	18,561,608
Total liabilities	12,487,276	9,930,009
Stockholders' equity	8,875,613	8,631,599

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,	
	2011	2010
Revenues:		
Oil sales	$ 6,364,308	$ 6,081,913
Natural gas sales	745,017	793,992
Total	$ 7,109,325	$ 6,875,905
Sales volumes:		
Oil (Bbls)	69,395	77,574
Natural gas (Mcf)	143,142	152,318
Total (BOE)	93,252	102,960
Average sales prices		
Oil ($/Bbl)	$ 91.71	$ 78.40
Natural gas ($/Mcf)	5.20	5.21
Total ($/BOE)	$ 76.24	$ 66.78
Costs and expenses ($/BOE)		
Lease operating	$ 20.78	$ 21.89
Production taxes	5.47	4.52
Depletion and depreciation	11.99	10.72
Impairment of oil and natural gas properties	14.56	5.24
Accretion of discount on asset retirement obligations	0.90	0.78
General and administrative	11.43	10.96
Total	$ 65.13	$ 54.11

Revenues

Oil and natural gas sales revenues increased by $233,420 or 3%, primarily due to increases in oil commodity prices. Oil sales increased $282,000 due to higher prices that contributed $923,000 to the increase in oil sales revenues but was offset by decreased production, the impact of which reduced oil sales by $641,000. Oil sales volumes decreased by 11%, primarily due to natural declines and downtime on wells waiting on repair. Natural gas sales decreased $48,975 or 6% due primarily to lower production in 2011. Oil and natural gas prices have been volatile during 2011 and the Company expects this to continue. FieldPoint's oil and natural gas sales revenue will be highly dependent on commodity prices in 2012.

Lease Operating Expenses

Lease operating expenses decreased by $315,547 or 14% due to a combination of decreased costs and decreased sales volumes. Costs decreased by $1.11 per barrel equivalent (BOE) or 5% in 2011 as compared to 2010. Decreased costs per equivalent unit contributed approximately $103,000 of the decrease in lease operating expense while decreased sales volumes contributed approximately $212,000 of the decrease. Many of FieldPoint's properties are mature and bear high operating expense.

Production Taxes

Production taxes increased $44,039 or 9%, primarily the result of increased oil and natural gas sales revenues as discussed above. Production taxes amounted to approximately 7.2% of oil and natural gas sales revenue during 2011 and 6.8% during 2010. Management expects production taxes to range between 6.5% and 7.5% of oil and natural gas sales revenue.

Depletion and Depreciation

Depletion and depreciation expense increased by $14,000 or 1%. The increase in depletion and depreciation was primarily due to depletion on a new well drilled in 2011, offset by overall decreases in production.

Impairment of Oil and Natural Gas Properties

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 Vaccuum 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. Impairment of $539,226 recorded during 2010 was primarily the result of the sale of the Whisler Unit at a net loss of approximately $11,000 in 2011.

General and Administrative Expense

General and administrative expenses decreased $62,778 or 6%. 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 between years.

Other Income (Expense)

The most significant component of other income and expense in 2011 and 2010 was interest expense. Interest expense decreased by $10,003 or 4%.

Liquidity and Capital Resources

Cash flow provided by operating activities was approximately $3.98 million for the year ended December 31, 2011, compared to $1.7 million for the year ended December 31, 2010. The increase in cash flow from operating activities was primarily due to the improvement in the results of oil and natural gas operations.

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. In 2010 FieldPoint used its operating cash flow along with cash on hand to fund $524,000 of development of oil and natural gas properties, to repay $4,755 of amounts outstanding under the Company's revolving line of credit, and to repurchase an aggregate of 293,000 shares of FieldPoint common stock for a total purchase price of $830,952 which were the primary components of cash used in financing activities in 2010. The repurchases were undertaken pursuant to a stock buy-back program approved by the Board of Directors. Management continuously searches for opportunities to make cost-effective acquisitions of oil and natural gas properties. 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, 2011, the Company had working capital of approximately $1 million and approximately $1.8 million borrowing capacity under its line of credit based on a borrowing base of $8.5 million. The borrowing base is subject to redetermination based on the value of proved reserves, and could be increased or decreased during 2012.

Although the Company had no significant commitments for capital expenditures at December 31, 2011, management anticipates continued investments in oil and natural gas properties during 2012. 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 2012 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, 2011, the Company had approximately $2.2 million of capital items in accounts payable that will be paid from working capital.

Subsequent Events

The Company's Board of Directors has declared a dividend to common stockholders of record on March 23, 2012 (the "Record Date") consisting of one common stock purchase warrant (the "Warrant Dividend" and "Warrant", respectively) for every share of common stock owned on the Record Date. Each Warrant will be exercisable for six years to purchase one share of common stock at an exercise price of $4.00 per share. The Company has the right to call the Warrants for redemption under certain circumstances. The Company has applied to have the Warrants approved for trading on the NYSE Amex separately from the common stock.

No prediction can be made if the Warrants will provide any significant additional working capital in the future.

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:

Cash Contractual Obligations	Obligation Due in Period				
	2012 (in thousands)	2013	2014	Thereafter	Total
Credit facility (secured)	$ —	$ —	$ 6,740	$ —	$ 6,740
Interest on credit facility	236	236	197	—	669
Total	$ 236	$ 236	6,937	$ —	$ 7,409

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 $1,237,568 of impairments on our proved oil and natural gas properties in 2011 and $539,226 of impairments of oil and natural gas properties in 2010.

Subsequent Events

In February 2012, the Company was advised by the well operator that the South Vacuum 35 #3 well in the South Vacuum Field in Lea County, New Mexico will be plugged and abandoned. This resulted in an impairment charge of approximately $838,000 which was recorded in the fourth quarter of 2011 based on capitalized costs through December 31, 2011. No material costs were incurred in 2012 and the net estimated plugging costs are approximately $25,000 which are included in current liabilities as of December 31, 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 Amex, have recently issued new requirements and regulations and are currently developing additional regulations and requirements in response to recent laws, enacted by Congress, most notably the Sarbanes-Oxley Act 2002 and the new SEC reporting regulations which became effective January 1, 2010. Our compliance with current and proposed rules requires the commitment of significant managerial resources. We conclude that our internal control over financial reporting was effective as of December 31, 2011.

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 authoritive 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 market 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, 2011 and December 31, 2010, there were no open positions. We did have derivative transactions during 2011.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

a) The Company's Principal Executive Officer and Principal Financial Officer, Ray Reaves, has established and is currently maintaining disclosure controls and procedures for the Company. The disclosure controls and procedures have been designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that it files under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and to ensure that information required to be disclosed by the Company is accumulated and communicated to the Company's management as appropriate to allow timely decisions regarding required disclosure.

The Principal Executive Officer and Principal Financial Officer conducted a review and evaluation of the effectiveness of the Company's disclosure controls and procedures and has concluded, based on his evaluation as of the end of the period covered by this Report, that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms and to ensure that the information required to be disclosed by the Company is accumulated and communicated to management, including our principal executive officer and our principal financial officer, to allow timely decisions regarding required disclosure.

b) There has been no change in our internal control over financial reporting during the fourth quarter ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Our principal executive and financial officer does not expect that our disclosure controls or internal controls will prevent all error and all fraud. Although our disclosure controls and procedures were designed to provide reasonable assurance of achieving their objectives and our principal executive and financial officer has determined that our disclosure controls and procedures are effective at doing so, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute assurance that the objectives of the system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented if there exists in an individual a desire to do so. There can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Internal control over financial reporting refers to the process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

1) Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;

2) Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and,

3) Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

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

Management has used the framework set forth in the report entitled "Internal Control – Integrated Framework" published by the Committee of Sponsoring Organizations of the Treadway Commission to evaluate the effectiveness of the Company's internal control over financial reporting. Management has concluded that the Company's internal control over financial reporting was effective as of the end of the most recent fiscal year.

This annual report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Form 10-K.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10 DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

(a) Identification of Directors and Executive Officers. The following table sets forth the names and ages of the Directors and Executive Officers of the Company, all positions and offices with the Company held by such person, and the time during which each such person has served:

Name	Age	Position with Company	Period Served
Ray D. Reaves	50	Director, President, Chairman, Chief Executive Officer	May 1997-present
Roger D. Bryant	69	Director	July 1997-present
Karl W. Reimers	70	Director	October 2004-present
Dan Robinson	64	Director	August 2004-present
Debra Funderburg	53	Director	February 2006-present

Mr. Reaves, age 50, has been Chairman, Director, President, Chief Executive Officer and Chief Financial Officer of the Company since May 22, 1997. Mr. Reaves has also served as Chairman, Chief Executive Officer, Chief Financial Officer and Director of Bass Petroleum, Inc. from October 1989 to the present, has 25 years experience in the oil and natural gas industry. He began his career in 1987, with North American Oil and Gas. Subsequently, in 1989 he purchased an interest in 10 of their wells and formed Bass Petroleum, Inc. Under Mr. Reaves' management in the years that followed, Bass Petroleum, Inc. gained majority control of the 10 original wells and acquired interest in another 60 wells. In 1998, Bass Petroleum merged with Energy Production Corporation and as a result, FieldPoint Petroleum Corporation was born.

Roger D. Bryant, age 69, has been a Director of the Company since July 1997. For more than twenty-five years, Mr. Bryant has held senior management positions with public and private start-up and turn-around technology companies in a number of different industries. He is currently President and CEO of Convergence Technology Application Partners, LLC (CTAP), a supplier of telecommunications systems. Prior positions include Chief Operations Officer for Electric and Gas Technologies, Inc., Chief Executive Officer of International Gateway Exchange, President and Chairman of Dial-thru International, Inc., President of Network Data Corporation, President of Dresser Industries, Inc., Wayne Division, President of Schlumberger Limited, Retail Petroleum Systems Division, U.S.A., a division of Schlumberger Corporation, and President of Autogas Systems, Inc., the developer of "Pay-at-the-Pump" technology for retail petroleum industry. All together, Mr. Bryant has held the Chief Executive position as well as serving on the board of directors, of more than ten private and public companies.

Mr. Reimers, age 70, is a CPA and has served as a director of the Company since October 2004. Mr. Reimers has held the position of President and CFO of B.A.G. Corp. from 1993 until his retirement in 2010. However, he continues as a financial consultant and director to B.A.G. Corp. He served as Vice President and CFO of Supreme Beef Company from 1989 to 1993. He also held the position of Vice President of Accounting at OKC Corp., a NYSE listed oil and gas company from 1975 to 1989. He was employed by Peat, Marwick, Mitchell, Certified Public Accountants, from 1973 to 1975, and he holds an MBA from the University of Texas at Arlington.

Mr. Robinson, age 64, has served as a director of the Company since August 2004. He has held the position of President and Chief Executive Officer of Placid Refining Company LLC from December 2004 to the present. Prior to his current position, he served in many capacities with Placid Oil Company beginning in March 1975, including the roles of Project Engineer, Manager of Refinery Operations, Assistant Secretary, Assistant Treasurer, Secretary, and Treasurer. Before beginning his 30 year oil and gas career he was briefly employed as a commercial credit analyst at First National Bank in Dallas. Mr. Robinson received a BS degree in Mechanical Engineering in 1971 and an MBA degree in Finance in 1973, both from the University of Wisconsin. He currently sits on the Board of Directors of the National Petrochemical and Refiners Association.

Debra Funderburg, age 53, has been a Director of the Company since February 6, 2006. From August 2010 to present she has served as Vice President Reservoir Engineering for Magnum Hunter Resources Corp. From September 2007 to August 2010 she served as Vice President of Business Development for Sanchez Oil & Gas. From May 2003 to August 2007 she has served as Senior Reservoir Engineer, Corporate A&D coordinator and Business Development manager for Dominion E&P. From November 1999 to May 2003 Ms. Funderburg held the position of Reservoir Engineering Manager for Randall & Dewey. From April 1993 to November 1999 she was employed by Pennzoil as a Senior Petroleum Engineer.

No family relationship exists between any director or executive officer.

There are no material proceedings to which any director, officer or affiliate of the Company, any owner of record or beneficially of more than five percent (5%) of any class of voting securities of the Company, or any associate of any such director, officer, affiliate of the Company, or security holder is a party adverse to the Company or any of its subsidiaries or has a material interest adverse to the Company or any of its subsidiaries.

During the last five (5) years no director or officer of the Company has:

a. had any bankruptcy petition filed by or against any business of which such person was a general partner or executive officer either at the time of the bankruptcy or within two years prior to that time;

b. been convicted in a criminal proceeding or subject to a pending criminal proceeding;

c. been subject to any order, judgment, or decree, not subsequently reversed, suspended or vacated, of any court of competent jurisdiction, permanently or temporarily enjoining, barring, suspending or otherwise limiting his involvement in any type of business, securities or banking activities; or

d. been found by a court of competent jurisdiction in a civil action, the Commission or the Commodity Futures Trading Commission to have violated a federal or state securities or commodities law, and the judgment has not been reversed, suspended, or vacated.

Any transactions between the Company and its officers, directors, principal shareholders, or other affiliates have been and will be on terms no less favorable to the Company than the Board of Directors believes could be obtained from unaffiliated third parties on an arms-length basis and will be approved by a majority of the Company’s independent, outside disinterested directors.

Meetings and Committees of the Board of Directors

a. Meetings of the Board of Directors

During the fiscal year ended December 31, 2011, six meetings of the Board of Directors were held, including regularly scheduled and special meetings, each of which were attended by all of the Directors. Meetings are conducted either in person or by telephone conference.

Outside Directors receive $500 per meeting and were reimbursed their expenses associated with attendance at such meetings or otherwise incurred in connection with the discharge of their duties as a Director. The outside Directors also received $5,000 in one time fees for the fiscal year end December 31, 2011. Except as otherwise provided below, Directors received a grant of options to purchase up to 100,000 shares of common stock at the date of their appointment and could receive an additional grant of options to purchase shares of common stock, as long as they continue to serve as directors. Ms. Funderburg receives a $12,000 annual retainer and is reimbursed for all expenses and received 10,000 shares of FieldPoint Petroleum Corp in 2006 for her service as a board member. The Company paid Roger Bryant a board member consulting fees of $4,000 during 2010 and Karl Reimers $500 in consulting fees. Effective January 1, 2011 the Company will no longer pay consulting fees to board members.

b. Committees

The board appoints committees to help carry out its duties. In particular, board committees work on key issues in greater detail than would be possible at full board meetings. Each committee reviews the result of its meetings with the full board.

During the year ended December 31, 2011, the board had a standing audit committee, a standing compensation committee, and a standing nomination committee.

Audit Committee

The audit committee was composed of the following directors:

Karl W. Reimers, Chairman
Dan Robinson
Roger D. Bryant

The Board of Directors has determined that Messrs. Reimers, Robinson and Bryant are “independent” within the meaning of the NYSE Amex’s listing standards and Item 407(a) of Regulation S-K. For this purpose, an audit committee member is deemed to be independent if he does not possess any vested interests related to those of management and does not have any financial, family or other material personal ties to management.

Karl Reimers, a member of the audit committee, qualifies as an “audit committee financial expert” within the meaning of Item 407(d)(5) of Regulation S-K.

During the fiscal year ended December 31, 2011 the audit committee had four meetings. The committee is responsible for accounting and internal control matters. The audit committee:

- reviews with management, the external consultants and the independent auditors policies and procedures with respect to internal controls;
- reviews significant accounting matters;
- approves any significant changes in accounting principles of financial reporting practices;
- reviews independent auditor services; and
- Recommends to the board of directors the firm of independent auditors to audit our consolidated financial statements.

In addition to its regular activities, the committee is available to meet with the independent accountants, external consultants whenever a special situation arises.

The Audit Committee of the Board of Directors has adopted a written charter, which has been previously filed with the Commission.

Audit Committee Report

The Audit Committee has reviewed and discussed the audited financial statements with management and with Hein & Associates LLP and the matters required to be discussed by AU Section 380. The Audit Committee has received the written disclosures and the letter from Hein & Associates LLP required by Independence Standards Board Standard No. 1 and has discussed with them their independence. Based on the review and discussions referred to above, the Audit Committee has recommended to the Board of Directors that the audited financial statements be included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2011 for filing with the Commission.

By the Audit Committee
Karl Reimers
Dan Robinson
Roger Bryant

Compensation Advisory Committee

The compensation advisory committee is currently composed of the following directors:

Dan Robinson, Chairman
Karl Reimers
Debbie Funderburg

The Board of Directors has determined that Messrs. Robinson, Reimers and Funderburg are "independent" within the meaning of the NYSE Amex's listing standards and Item 407(a) of Regulation S-K. For this purpose, a compensation committee member is deemed to be independent if he does not possess any vested interests related to those of management and does not have any financial, family or other material personal ties to management.

During the fiscal year ended December 31, 2011 the compensation advisory committee had two meetings. The compensation advisory committee:

- Recommends to the board of directors the compensation and cash bonus opportunities based on the achievement of objectives set by the compensation advisory committee with respect to our chairman of the board and president, our chief executive officer and the other executive officers;
- administers our compensation plans for the same executives;
- determines equity compensation for all employees;
- reviews and approves the cash compensation and bonus objectives for the executive officers; and
- reviews various matters relating to employee compensation and benefits.

Nomination Committee

The nomination committee was composed of the following directors:

Roger D. Bryant, Chairman
Karl Reimers
Debbie Funderburg

Of the currently serving three members Messrs. Bryant, Reimers and Funderburg, would each be deemed to be independent within the meaning of the NYSE Amex's listing standards and Item 407(a) of Regulation S-K. For this purpose, a director is deemed to be independent if he does not possess any vested interests related to those of management and does not have any financial, family or other material personal ties to management the committee had one meeting in 2011.

The board of directors has not adopted a policy with regard to the consideration of any director candidates recommended by security holders, since to date the board has not received from any security holder a director nominee recommendation. The board of directors will consider candidates recommended by security holders in the future. Security holders wishing to recommended a director nominee for consideration should contact Mr. Ray Reaves, Chief Executive Officer and Chief Financial Officer, at the Company's principal executive offices located in Cedar Park, Texas and provide to Mr. Reaves, in writing, the recommended director nominee's professional resume covering all activities during the past five years, the information required by Item 401 of Regulation S-X, and a statement of the reasons why the security holder is making the recommendation. Such recommendation must be received by the Company before December 31, 2012.

The board of directors believes that any director nominee must possess significant experience in business and/or financial matters as well as a particular interest in the Company's activities.

All director nominees identified in this proxy statement were recommended by our President and Chief Financial Officer and unanimously approved by the board of directors.

Shareholder Communications

Any shareholder of the Company wishing to communicate to the board of directors may do so by sending written communication to the board of directors to the attention of Mr. Ray Reaves, Chief Executive Officer and Chief Financial Officer, at the principal executive offices of the Company. The board of directors will consider any such written communication at its next regularly scheduled meeting.

Any transactions between the Company and its officers, directors, principal shareholders, or other affiliates have been and will be on terms no less favorable to the Company than could be obtained from unaffiliated third parties on an arms-length basis and will be approved by a majority of the Company's independent, outside disinterested directors.

Code of Ethics

Our Board of Directors adopted a Code of Business Conduct and Ethics for all of our directors, officers and employees during the fiscal year ended December 31, 2003. Our Code of Business Conduct and Ethics can be found at our website address: http://www.fppcorp.com. We will provide to any person without charge, upon request, a copy of our Code of Business Conduct and Ethics. Such request should be made in writing and addressed to Investor Relations, FieldPoint Petroleum Corporation, 1703 Edelweiss Drive, Cedar Park, Texas 78613. Further, our Code of Business Conduct and Ethics is filed as an exhibit to the Company's Annual Report on Form 10-KSB for the fiscal year ending December 31, 2003.

COMPLIANCE WITH SECTION 16(a) OF THE SECURITIES EXCHANGE ACT

Section 16 (a) of the Securities Exchange Act of 1934, as amended, requires the Company's executive officers, directors and persons who own more than ten percent of the Common Stock (collectively, "Reporting Persons") to file initial reports of ownership and changes of ownership of the Common Stock with the SEC and the NYSE Amex. Reporting Persons are required to furnish the Company with copies of all forms that they file under Section 16(a). Based solely upon our search of publicly available information or information provided to the Company from Reporting Persons, during the two years ended December 31, 2011, the Company is not aware of any failure on the part of any Reporting Persons to timely file reports required pursuant to Section 16(a).

ITEM 11 EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

Introduction. This Compensation Discussion and Analysis ("CD&A") provides an overview of the Company's executive compensation program together with a description of the material factors underlying the decisions which resulted in the compensation provided for 2011 to the Company's Chief Executive Officer ("CEO") (the "Named Executive Officers" or "NEOs"), as presented in the tables which follow this CD&A. The following discussion and analysis contains statements regarding future individual and Company performance targets and goals. These targets and goals are disclosed in the limited context of the Company's compensation programs and should not be understood to be statements of management's expectations or estimates of financial results or other guidance. The Company specifically cautions investors not to apply these statements to other contexts.

Compensation Committee. The Compensation Committee (the "Committee") of the Board of Directors is composed of three non-employee Directors, all of whom are independent under the guidelines of the NYSE Amex listing standards. The current Committee members are Dan Robinson, Karl Reimers and Debbie Funderburg. The Committee has responsibility for determining and implementing the Company's philosophy with respect to executive compensation. To implement this philosophy, the Committee oversees the establishment and administration of the Company's executive compensation program.

Compensation Philosophy and Objectives. The guiding principle of the Committee's executive compensation philosophy is that the executive compensation program should enable the Company to attract, retain and motivate a team of highly qualified executives who will create long-term value for the Shareholders. To achieve this objective, the Committee has developed an executive compensation program that is ownership-oriented and that rewards the attainment of specific annual, long-term and strategic goals that will result in improvement in total shareholder return. To that end, the Committee believes that the executive compensation program should include both cash and equity-based compensation that rewards specific performance. In addition, the Committee continually monitors the effectiveness of the program to ensure that the compensation provided to executives remains competitive relative to the compensation paid to executives in a peer group comprised of select container industry and other manufacturing companies. The Committee annually evaluates the components of the compensation program as well as the desired mix of compensation among these components. The Committee believes that a substantial portion of the compensation paid to the Company's NEOs should be at risk, contingent on the Company's operating and market performance. Consistent with this philosophy, the Committee will continue to place significant emphasis on stock-based compensation and performance measures, in an effort to more closely align compensation with Shareholder interests and to increase executives' focus on the Company's long-term performance.

Committee Process. The Committee meets as often as necessary to perform its duties and responsibilities. The Committee usually meets with the CEO and CFO. In addition, the Committee periodically meets in executive session without management.

The Committee's meeting agenda is normally established by the Committee Chairperson in consultation with the CEO and CFO. Committee members receive and review materials in advance of each meeting. Depending on the meeting's agenda, such materials may include: financial reports regarding the Company's performance, reports on achievement of individual and corporate objectives, reports detailing executives' stock ownership and options, tally sheets setting forth total compensation and information regarding the compensation programs and levels of certain peer group companies.

Role of Executive Officers in Compensation Decisions. The Committee makes all compensation decisions for the CEO and the CFO. Decisions regarding the compensation of other employees are made by the CEO and CFO in consultation with the Committee. In this regard, the CEO and CFO provide the Committee evaluations of executive performance, business goals and objectives and recommendations regarding salary levels and equity awards.

Market-Based Compensation Strategy. The Committee adopted the following market-based compensation strategy:

- Pay levels are evaluated and calibrated relative to other companies of comparable size operating in the oil and gas exploration business (the "Peer Group") as the primary market reference point. In addition, general industry data is reviewed as an additional market reference and to ensure robust competitive data.
- Target total direct compensation (target total cash compensation plus the annualized expected value of long-term incentives) levels for NEOs are calibrated relative to the Peer Group.
- Base salary and target total cash compensation levels (base salary plus target annual incentive) for NEOs are calibrated to the Peer Group.
- The long-term incentive component of the executive compensation program is discretionary and viewed in light of the target total direct compensation level.

The Committee retains discretion, however, to vary compensation above or below the targeted percentile based upon each NEO's experience, responsibilities and performance.

Total Direct Compensation

Our objective is to target total direct compensation, consisting of cash salary, cash bonus and long term equity compensation at levels consistent with the surveyed companies, if specified corporate and business unit performance metrics and individual performance objectives are met. We selected this target for compensation to remain competitive in attracting and retaining talented executives. Many of our competitors are significantly larger and have financial resources greater than our own. The competition for experienced, technically proficient executive talent in the oil and gas industry is currently particularly acute, as companies seek to draw from a limited pool of such executives to explore for and develop hydrocarbons that increasingly are in more remote areas and are technologically more difficult to access.

Components of Compensation. For the years ended December 31, 2011 and 2010, the sole component of compensation for the CEO was base salary. We did provide additional compensation in the form of annual incentive bonus and perquisites.

Base Salary. The Company provides the CEO with base salaries to compensate him for services rendered during the year. The Committee believes that competitive salaries must be paid in order to attract and retain high quality executives. The Committee reviews the CEO's salary at the end of each year, with any adjustments to base salary becoming effective on January 1 of the succeeding year.

In determining base salary level for executive officers, the committee considers the following qualitative and quantitative factors:

- job level and responsibilities,
- relevant experience,
- individual performance,
- recent corporate performance.

We review base salaries annually, but we do not necessarily award salary increases each year. From time to time base salaries may be adjusted other than as a result of an annual review, in order to address competitive pressures or in connection with a promotion.

Base salaries paid to the CEO is deductible for federal income tax purposes except to the extent that the executive's aggregate compensation which is subject to Section 162(m) of the Internal Revenue Code (the "Code") exceeds $1 million.

The following tables and discussion set forth information with respect to all plan and non-plan compensation awarded to, earned by or paid to the Chief Executive Officer ("CEO"), and the Company's four (4) most highly compensated executive officers other than the CEO, for all services rendered in all capacities to the Company and its subsidiaries for each of the Company's last three (3) completed fiscal years; provided, however, that no disclosure has been made for any executive officer, other than the CEO, whose total annual salary and bonus does not exceed $100,000.

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus	Stock Awards	Options Awards	Non equity Incentive Plan Compensation	Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
Ray D. Reaves, CEO, President	2011	$250,000	$ 56,548	—	—	—	—	—	$306,548
Ray D. Reaves, CEO, President	2010	$250,000	$175,000	—	—	—	—	—	$425,000
Ray D. Reaves, CEO, President	2009	$225,000	$ 45,750	—	—	—	—	—	$270,750

Bonus Plan

In 2008, the Company's Board of Directors adopted a Performance Based Bonus Program for the President and CEO (the "Bonus Plan"). Under the Bonus Plan, the President can earn an annual bonus based upon four parameters: (i) annual reserve additions from drilling and acquisitions as measured by the Board approved Annual Business Plan ("Business Plan") ("Reserve Bonus"), (ii) growth in annual production as measured by the Business Plan, ("Production Bonus") (iii) growth in annual year over year earnings before taxes and bonus ("EBBT")("Earnings Bonus"), and (iv) other notable achievements as determined by the Board ("Achievement Bonus").

To earn any of the Reserve Bonus, Production Bonus or Earnings Bonus, the Company's performance must exceed the goal or target set by the Board in the Business Plan. If actual reserve additions for the year exceed the Business Plan target, a bonus will be paid equal to the percentage that the actual reserve additions bears to the total reserves reported in the previous year's Annual Report on Form 10-K (the "Prior 10-K"), not to exceed 50% of Base Salary. If actual production for the year exceeds the Business Plan target, a bonus will be paid equal to the percentage that the actual production bears to the total production reported in the Prior 10-K, not to exceed 50% of Base Salary. If actual EBBT for the year exceeds the Business Plan target, a bonus will be paid equal to the percentage that actual EBBT bears to EBBT as reported in the Prior 10-K, not to exceed 50% of Base Salary. The Achievement Bonus is discretionary with the Board and cannot exceed 10% of Base Salary. The maximum cumulative bonus payable in any given year may not exceed 150% of Base Salary.

The following table sets forth information concerning unexercised options, stock that has not vested and equity incentive plan awards for each named executive officer outstanding as of the end of the most recently completed fiscal year:

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR END TABLE

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Equity Incentive Plan Awards; Number of Securities Underlying Unexercised Unearned Options	Option Exercise Price	Option Exercise Date	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares of Units That Have Not Vested	Equity Incentive Plan Awards; Number of Unearned Shares, Units or Other Rights That Have Not Vested	Equity Incentive Plan Awards; Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested
Ray Reaves	- 0 -	- 0 -	—	—	—	- 0 -	—	—	—

The following table sets forth information concerning compensation paid to the Company's directors during the most recently completed fiscal year:

DIRECTOR COMPENSATION TABLE

Name	Fees Earned or Paid in Cash	Stock Awards	Option Awards	Non-Equity Incentive Plan Compensation	Nonqualified Deferred Compensation Earnings	All Other Compensation	Total
Roger Bryant	$ 6,000	—	—	—	—	—	$ 6,000
Karl Reimers	$ 6,000	—	—	—	—	—	$ 6,000
Dan Robinson	$ 6,000	—	—	—	—	—	$ 6,000
Debra Funderburg	$17,000	—	—	—	—	—	$17,000

Option Grants Table

There were no stock option grants for fiscal years ended December 31, 2010 and 2011.

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

The following table sets forth information with respect to beneficial ownership of our common stock by:

- each person who beneficially owns more than 5% of the common stock;
- each of our executive officers named in the Management section;
- each of our Directors; and
- all executive officers and Directors as a group.

The table shows the number of shares owned as of March 20, 2012 and the percentage of outstanding common stock owned as of March 20, 2012. Each person has sole voting and investment power with respect to the shares shown, except as noted.

Name and Address Of Beneficial Owner[(2)]	Amount and Nature of Beneficial Owner	Percent of Class [(1)]
Ray D. Reaves	3,180,000 [(3)]	39.8%
Roger D. Bryant	26,000	*
Dan Robinson	96,000	1.2%
Karl Reimers	62,000	1.0%
Debbie Funderburg	16,000	*
All Officers and Directors as a Group (6 persons)	3,380,000	42.3%

* indicates less than 1%

(1) The percentages shown are calculated based upon 7,983,175[cn3] shares of common stock issued and outstanding at March 20, 2012. In calculating the percentage of ownership, unless as otherwise indicated, all shares of common stock that the identified person or group had the right to acquire within 60 days of the date of this Annual Report upon the exercise of options and warrants or conversion of notes are deemed to be outstanding for the purpose of computing the percentage of shares of common stock owned by such person or group, but are not deemed to be outstanding for the purpose of computing the percentage of the shares of common stock owned by any other person.

(2) Unless otherwise stated, the beneficial owner's address is 1703 Edelweiss Drive, Cedar Park, Texas 78613.

(3) Includes 160,000 shares held by Bass Petroleum, Inc., of which Mr. Reaves is executive officer. Mr. Reaves disclaims beneficial ownership of these shares for purposes of Section 16 of the Exchange Act.

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

The Company leases office space from its majority shareholder. The lease requires monthly payments of $2,500 on a month to month basis. The Company paid Karl Reimers $500 in consulting fees in 2010 and paid Roger Bryant, a director $4,000 in consulting fees in 2010.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

In the last two fiscal years, we have retained Hein & Associates LLP ("Hein") as our independent and registered public accounting firm. Hein audited our consolidated financial statements for fiscal 2011 and 2010. We understand the need for our principal accountants to maintain objectivity and independence in their audit of our financial statements. To minimize relationships that could appear to impair the objectivity of our principal accountants, our audit committee has restricted the non-audit services that our principal accountants may provide to us primarily to tax services and audit related services. The board has adopted policies and procedures for pre-approving work performed by our principal accountants.

After careful consideration, the Audit Committee of the Board of Directors has determined that payment of the below audit fees is in conformance with the independent status of the Company's principal independent accountants. Before engaging the auditors in additional services, the Audit Committee considers how these services will impact the entire engagement and independence factors.

The following is an aggregate of fees billed for each of the last two fiscal years for professional services rendered by our principal accountants:

	2011	2010
Audit fees – audit of annual financial statements and review of financial statements included in our quarterly reports, services normally provided by the accountant in connection with statutory and regulatory filings.	$ 98,300	$ 87,400
Audit-related fees – related to the performance of audit or review of financial statements not reported under "audit fees" above		—
Tax fees – tax compliance, tax advice and tax planning	19,400	19,400
All other fees – services provided by our principal accountants other than those identified above	—	—
Total fees paid or accrued to our principal accountants	$ 117,700	$ 106,800

ITEM 15 EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Exhibits

3.1	Articles of Incorporation (incorporated by reference to Amendment No. 1 to Form S-2 dated August 1, 1980.)
3.2(b)	Articles of Amendment of Articles of Incorporation, dated December 31, 1997 (incorporated by reference to the Company's 10KSB for the year ended December 31, 1997.)
3.3	Bylaws (incorporated by reference to Amendment No. 1 to Form S-2 dated August 1, 1980.)
4.1	Plan of Exchange (incorporated by reference to the Company's definitive proxy statement dated December 8, 1997).
4.2	Indenture (Term Loan) dated June 21, 1999 by and among the Company and Union Planters Bank
4.3	Indenture (Term Loan) dated August 18, 1999 by and among the Company and Union Planters Bank
4.4	Stock Option Agreement (incorporated by reference to the Company's Form S-8 dated May 27, 2005 as filed with the Commission on May 27, 2005.)
4.5	Warrant Agreement and Form of Warrant Certificate (incorporated by reference to the Company's Form S-3 as filed with the Commission on November 22, 2011.)
10.1	Consulting Agreement dated May 9, 2000 between FieldPoint Petroleum Corp. and Parrish Brian & Co. (incorporated by reference to the Company's 10QSB/A for the quarter ended September 30, 2000)
10.2	Executive Employment Agreement, dated March 28, 2001, by and among FieldPoint Petroleum Corp. and Ray D. Reaves (incorporated by reference to the Company's 10KSB for the year ended December 31, 2000.)
10.3	Credit Agreement (Revolving Credit Note) dated December 14, 2000 by and among FieldPoint Petroleum Corp. and Union Planters Bank (incorporated by reference to the Company's 10KSB for the year ended December 31, 2000.)
10.4	Audit Committee Charter adopted by the Company on March 28, 2001(incorporated by reference to the Company's 10KSB for the year ended December 31, 2000.)
10.5	Consulting Agreement dated November 13, 2001 between FieldPoint Petroleum Corp. and TRG Group LLC. (incorporated by reference to the Company's 10QSB for the quarter ended September 30, 2001)
10.6	Loan and Security Agreement with CitiBank, N.A., dated October 18, 2006 (incorporated by reference from the Company's current report on Form 8k dated October 18, 2006 as filed with the Commission on October 20, 2006.)
10.7	Lease Assignment from PXP Gulf Coast, Inc., dated March 11, 2004, incorporated by reference from the Company's Current Report on Form 8-K dated March 11, 2004, as filed with the Commission on March 26, 2004.

10.8	Securities Purchase Agreement (incorporated by reference to the Company's Form SB-2 dated September 20, 2005 as filed with the Commission on September 20, 2005.)
10.9	Registration Rights Agreement (incorporated by reference to the Company's Form S-8 dated May 27, 2005 as filed with the Commission on May 27, 2005.)
10.10	Stock Purchase Agreement (incorporated by reference to the Company's Form 8-K dated February 6, 2006 as filed with the Commission on February 9, 2006.)
10.11	Board Compensation Agreement (incorporated by reference to the Company's Form 8-K dated February 6, 2006 as filed with the Commission on February 9, 2006.)
10.12	Security Agreement (incorporated by reference to the Company's Form 8-K dated October 18, 2006 as filed with the Commission on October 20, 2006).
10.13	Bonus Program (incorporated by reference to the Company's Form 8-K dated October 24, 2008 as filed with the Commission on October 29, 2008.)
10.14	Guaranty Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)
10.15	First Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)
10.16	Second Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)
10.17	Third Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)
10.18	Fourth Amendment to Loan & Security Agreement (incorporated by reference to the Company's Form 10-Q dated September 30, 2009 as filed with the Commission on November 16, 2009.)
14.	Code of Ethics (incorporated by reference to the Company's Annual Report on Form 10-KSB for the year ended December 31, 2003 as filed with the Commission on April 14, 2004.)
23	Consent of Hein & Associates, LLP
31	Certification required by Section 13a-14(a) of the Exchange Act.
32	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 Certification required by Section 13a-14(a) of the Exchange Act.
99.1	Reserve & Economic Evaluation Report (incorporated by reference to the Company's Form 10-K dated December 31, 2010 as filed with the Commission on March 30, 2011.)

99.2 Estimates of Future Reserve & Revenues Report (incorporated by reference to the Company's Form 10-K dated December 31, 2010 as filed with the Commission on March 30, 2011.)

99.3 Letter Report and Certificate of Qualification of Fletcher Lewis Engineering, Inc.

99.4 Letter Report and Certificate of Qualification of PGH Petroleum & Environmental Engineers, L.L.C.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

FIELDPOINT PETROLEUM CORPORATION
(Registrant)

Date: March 20, 2012

By: /s/ Ray Reaves
Ray Reaves, President

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

By: /s/ Ray Reaves
President, Chief Executive Officer,
Director, Chairman, Chief Financial Officer

Date: March 20, 2012

By: /s/ Roger D. Bryant
Roger D Bryant
Director

Date: March 20, 2012

By: /s/ Dan Robinson
Dan Robinson
Director

Date: March 20, 2012

By: /s/ Karl W. Reimers
Karl W. Reimers
Director

Date: March 20, 2012

By: /s/ Debra Funderburg
Debra Funderburg
Director

Date: March 20, 2012

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, 2011 and 2010, 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, 2011 and 2010, 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, 2012

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 2,037,593	$ 984,770
Certificates of deposit	44,469	44,422
Accounts receivable:		
Oil and natural gas sales	1,007,025	723,218
Joint interest billings, less allowance for doubtful accounts of $99,000 each period	209,209	246,655
Income taxes receivable	332,134	206,000
Deferred income tax asset-current	58,000	99,000
Prepaid drilling expenses	—	975,538
Prepaid expenses and other current assets	121,745	76,433
Total current assets	3,810,175	3,356,036
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties (successful efforts method)	27,616,928	24,434,664
Other equipment	52,113	89,248
Less accumulated depletion and depreciation	(10,116,327)	(9,318,340)
Net property and equipment	17,552,714	15,205,572
Total assets	$ 21,362,889	$ 18,561,608
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued expenses	$ 2,506,145	$ 553,760
Oil and natural gas revenues payable	259,129	198,247
Asset retirement obligation – current	25,000	—
Total current liabilities	2,790,274	752,007
LONG-TERM DEBT	6,740,000	6,740,000
DEFERRED INCOME TAXES	1,467,000	1,033,000
ASSET RETIREMENT OBLIGATION	1,490,002	1,405,002
Total liabilities	12,487,276	9,930,009
COMMITMENTS AND CONTINGENCIES (Notes 7 and 8)		
STOCKHOLDERS' EQUITY:		
Common stock, $.01 par value, 75,000,000 shares authorized; 8,910,175 shares issued, each period; 7,983,175 and 8,077,175 outstanding, respectively	89,101	89,101
Additional paid-in capital	4,573,580	4,573,580
Retained earnings	6,179,824	5,577,260
Treasury stock, 927,000 and 833,000 shares, respectively, at cost	(1,966,892)	(1,608,342)
Total stockholders' equity	8,875,613	8,631,599
Total liabilities and stockholders' equity	$ 21,362,889	$ 18,561,608

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	December 31, 2011	December 31, 2010
REVENUE:		
Oil and natural gas sales	$ 7,109,325	$ 6,875,905
Well operational and pumping fees	68,265	68,265
Disposal fees	58,270	64,613
Total revenue	7,235,860	7,008,783
COSTS AND EXPENSES:		
Lease operating	2,447,544	2,719,052
Depletion and depreciation	1,118,000	1,104,000
Impairment of oil and natural gas properties	1,357,339	539,226
Accretion of discount on asset retirement obligations	84,000	80,000
General and administrative	1,066,020	1,128,798
Total costs and expenses	6,072,903	5,571,076
OPERATING INCOME	1,162,957	1,437,707
OTHER INCOME (EXPENSE):		
Interest income	5,054	5,366
Interest expense	(238,795)	(248,798)
Loss on sale of oil and gas property	(10,670)	—
Miscellaneous income	71,018	43,195
Total other income (expense)	(173,393)	(200,237)
INCOME BEFORE INCOME TAXES	989,564	1,237,470
INCOME TAX PROVISION – current	(12,000)	(245,000)
INCOME TAX PROVISION – deferred	(375,000)	(205,000)
TOTAL INCOME TAX PROVISION	(387,000)	(450,000)
NET INCOME	$ 602,564	$ 787,470
EARNINGS PER SHARE:		
BASIC	$ 0.08	$ 0.10
DILUTED	$ 0.08	$ 0.10
WEIGHTED AVERAGE SHARES OUTSTANDING:		
Basic	8,015,878	8,200,541
Diluted	8,015,878	8,200,541

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010

	Common Stock		Additional Paid-in	Retained	Treasury Stock		
	Shares	Amount	Capital	Earnings	Shares	Amount	Total
BALANCES, January 1, 2010	8,910,175	$ 89,101	$ 4,573,580	$ 4,789,790	540,000	$ (777,390)	$ 8,675,081
Purchase of treasury shares	—	—	—	—	293,000	(830,952)	(830,952)
Net income	—	—	—	787,470	—	—	787,470
BALANCES, December 31, 2010	8,910,175	89,101	4,573,580	5,577,260	833,000	(1,608,342)	8,631,599
Purchase of treasury shares	—	—	—	—	94,000	(358,550)	(358,550)
Net income	—	—	—	602,564	—	—	602,564
BALANCES, December 31, 2011	8,910,175	$ 89,101	$ 4,573,580	$ 6,179,824	927,000	$ (1,966,892)	$ 8,875,613

FIELDPOINT PETROLEUM CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	December 31, 2011	December 31, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 602,564	$ 787,470
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on sale and abandonment of oil and gas property	10,670	—
Depletion and depreciation	1,118,000	1,104,000
Impairment of oil and gas properties	1,357,339	539,226
Deferred income taxes	375,000	205,000
Accretion of discount on asset retirement obligations	84,000	80,000
Changes in assets and liabilities:		
Accounts receivable	(246,361)	(42,297)
Income taxes receivable	(126,134)	(115,677)
Prepaid expenses and other current assets	930,226	(950,022)
Accounts payable and accrued expenses	(185,194)	125,248
Oil and natural gas revenues payable	60,882	18,881
Other	(47)	(65,412)
Net cash provided by operating activities	3,980,945	1,686,417
CASH FLOWS FROM INVESTING ACTIVITIES:		
Additions to oil and natural gas properties	(2,610,417)	(523,882)
Proceeds from the sale of oil and natural gas properties	68,330	—
Acquisition of other equipment	(27,485)	—
Net cash used in investing activities	(2,569,572)	(523,882)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Repayments of long-term debt	—	(4,755)
Purchase of treasury shares	(358,550)	(830,952)
Net cash used in financing activities	(358,550)	(835,707)
NET INCREASE IN CASH	1,052,823	326,828
CASH, beginning of year	984,770	657,942
CASH, end of the year	$ 2,037,593	$ 984,770
SUPPLEMENTAL INFORMATION:		
Cash paid during the year for interest	$ 238,795	$ 248,798
Cash paid during the year for income taxes	$ 70,000	$ 400,000
Capital items in accounts payable	$ 2,237,579	$ —

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

FieldPoint Petroleum Corporation (the "Company", "we" or "our") is incorporated under the laws of the state of Colorado. We are engaged in the acquisition, operation and development of oil and natural gas properties, which are located in Louisiana, New Mexico, Oklahoma, South Central Texas and Wyoming as of December 31, 2011 and 2010.

Consolidation Policy

Our consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, Bass Petroleum, Inc. and Raya Energy Corp. All material intercompany accounts and transactions have been eliminated in consolidation.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. At times, we maintain deposit balances in excess of FDIC insurance limits. We have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk on cash and cash equivalents.

Certificates of Deposit

Certificates of deposit have original maturities ranging from three months to one year and are recorded at fair value on the balance sheet in current assets. Changes in fair value during the period are classified as realized or unrealized holding gains in other income.

Oil and Natural Gas Properties

Our oil and natural gas properties consisted of the following at December 31:

	2011	2010
Mineral interests in properties:		
Unproved properties	$ 850,000	$ 969,771
Proved properties	20,410,676	17,200,475
Equipment and facilities	6,356,252	6,264,418
Total costs	27,616,928	24,434,664
Less accumulated depletion and depreciation	(10,088,699)	(9,229,092)
	$ 17,528,229	$ 15,205,572

We follow the successful efforts method of accounting for our oil and natural gas producing activities. Costs to acquire mineral interests in oil and natural gas properties, to drill and equip exploratory wells that find proved reserves, to drill and equip development wells and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determination of whether the wells have found proved reserves. If we determine that the wells do not find proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determination of whether the wells found proved reserves at December 31, 2011 or 2010. Geological and geophysical costs, including seismic studies and costs of carrying and retaining unproved properties are charged to expense as incurred.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We capitalize interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. Through December 31, 2011, we have capitalized no interest costs because our exploration and development projects generally last less than six months. Costs to maintain wells and related equipment are charged to expense as incurred.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion and depreciation are eliminated from the property accounts, and the resulting gain or loss is recognized. On the sale of a partial unit of proved property, the amount received is treated as a reduction of the cost of the interest retained.

Capitalized amounts attributable to proved oil and natural gas properties are depleted by the unit-of-production method of proved reserves using the unit conversion ratio of 6 Mcf of gas to 1 bbl of oil. Depletion and depreciation expense for oil and natural gas producing property and related equipment was $1,115,000 and $1,102,435 for the years ended December 31, 2011 and 2010, respectively.

Unproved oil and natural gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. An impairment of unproved properties of $119,771 was recorded during the year ended December 31, 2011. No impairment of unproved properties was recorded during the years ended December 31, 2010.

Capitalized costs related to proved oil and natural gas properties, including wells and related equipment and facilities, are evaluated for impairment based on an analysis of undiscounted future net cash flows. If undiscounted cash flows are insufficient to recover the net capitalized costs related to proved properties, then we recognize an impairment charge in income from operations equal to the difference between the net capitalized costs related to proved properties and their estimated fair values based on the present value of the related future net cash flows, which is a non-recurring fair value measurement classified as Level 3 in the fair value hierarchy. We 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 during the year ended December 31, 2011. We recorded an impairment of $539,226 during the year ended December 31, 2010 on our proved oil and natural gas properties. The impairment was primarily the result of writing down the book value of the Whistler property sold in January 2011.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

<u>*Oil and Natural Gas Sales Receivable*</u>

Oil and natural gas sales receivable principally consist of accrued oil and natural gas sales proceeds receivable and are typically collected within 35 days from the end of the month in which the related quantities are produced. We ordinarily do not require collateral for such receivables, nor do we charge interest on past due balances. We periodically review accounts receivable for collectability and reduce the carrying amount of the accounts receivable by an allowance. No such allowance was indicated at December 31, 2011 or 2010. As of December 31, 2011, our accounts receivable were primarily with several independent purchasers of our crude oil and natural gas production. At December 31, 2011, we

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

had balances due from five customers which were greater than 10% of our accounts receivable related to crude oil and natural gas production. These five customers accounted for 80% of accounts receivable at December 31, 2011. At December 31, 2010, we had balances due from two customers which were greater than 10% of our accounts receivable related to crude oil and natural gas production. These two customers accounted for 48% of accounts receivable at December 31, 2010. In the event that one or more of these significant customers ceases doing business with us, we believe that there are potential alternative customers with whom we could establish new relationships and that those relationships would result in the replacement of one or more lost customers.

Joint Interest Billings Receivable and Oil and Natural Gas Revenues Payable

Joint interest billings receivable represent amounts receivable for lease operating expenses and other costs due from third party working interest owners in the wells that the Company operates. The receivable is recognized when the cost is incurred and the related payable and the Company's share of the cost is recorded. We often have the ability to offset amounts due against the participant's share of production from the related property.

The Company uses the reserve for bad debt method of valuing doubtful joint interest billings receivable based on historical experience, coupled with a review of the current status of existing receivables. The balance of the reserve for doubtful accounts, deducted against joint interest billings receivable to properly reflect the realizable value was $99,000 at December 31, 2011 and 2010.

Oil and natural gas revenues payable represents amounts due to third party revenue interest owners for their share of oil and natural gas revenue collected on their behalf by the Company. The payable is recorded when the Company recognizes oil and natural gas sales and records the related oil and natural gas sales receivable.

Other Property

Other assets classified as property and equipment are primarily office furniture and equipment and vehicles, which are carried at cost. Depreciation is provided using the straight-line method over estimated useful lives ranging from three to five years. Gain or loss on retirement or sale or other disposition of assets is included in income in the period of disposition. Depreciation expense for other property and equipment was $3,000 and $1,565 for each of the years ended December 31, 2011 and 2010.

Asset Retirement Obligations

Our financial statements reflect our asset retirement obligations, consisting of future plugging and abandonment expenditures related to our oil and natural gas properties, which can be reasonably estimated. The asset retirement obligation is recorded at fair value on a discounted basis as a liability at the asset's inception, with an offsetting increase to producing properties on the consolidated balance sheets. Periodic accretion of the discount of the estimated liability is recorded as an expense in the consolidated statements of operations.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31:

	2011	2010
Asset retirement obligation at January 1,	$ 1,405,002	$ 1,325,002
Accretion of discount	84,000	80,000
Liabilities incurred during the year	26,000	—
Liabilities settled during the year	—	—
Asset retirement obligation at December 31,	$ 1,515,002	$ 1,405,002

The portion of the balance classified as a current liability was $25,000 and $0 at December 31, 2011 and 2010, respectively. The remainder of the balance was classified as non-current in each year.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently due, if any, plus net deferred taxes related to differences between the bases of assets and liabilities for financial and income tax reporting. Deferred tax assets and liabilities represent the future tax consequences of those differences, which will either be taxable or deductible when the assets and liabilities are recovered or settled. Valuation allowances are recognized to limit recognition of deferred tax assets where appropriate. Such allowances may be reversed when circumstances provide evidence that the deferred tax assets will more likely than not be realized.

Production Taxes and Ad Valorem Taxes

Production taxes and ad valorem taxes are included in lease operating expense. Total production and ad valorem taxes were $606,786 and $629,307 for the years ended December 31, 2011 and 2010, respectively.

Use of Estimates and Certain Significant Estimates

The preparation of the Company's financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company's management to make estimates and assumptions that affect the amounts reported in these financial statements and accompanying notes. Actual results could differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, which as described above may affect the amount at which oil and natural gas properties are recorded. The Company's allowance for doubtful accounts is a significant estimate and is based on management's estimates of uncollectible receivables. The asset retirement obligations require estimates of future plugging and abandonment expenditures. It is at least reasonably possible these estimates could be revised in the near term and the revisions could be material.

Our estimates of proved reserves materially impact depletion and impairment expense. If proved reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in estimates of proved reserves may result from lower prices, evaluation of additional operating history, mechanical problems at our wells and catastrophic events such as explosions, hurricanes and floods. Lower prices also may make it uneconomical to drill wells or produce from fields with high operating costs. In addition, a decline in proved reserves may impact our assessment of our oil and natural gas properties for impairment.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Our proved reserve estimates are a function of many assumptions, all of which could deviate materially from actual results. As such, reserve estimates may vary materially from the ultimate quantities of oil and natural gas actually produced.

Revenue Recognition

The Company uses the sales method of accounting for oil and natural gas revenues. Under this method, revenues are based on actual volumes of oil and natural gas sold to purchasers. The volumes of natural gas sold may differ from the volumes to which the Company is entitled based on its interest in the properties. Differences between volumes sold and volumes based on entitlements create natural gas imbalances. Material imbalances are reflected as adjustments to reported natural gas reserves and future cash flows. There were no material natural gas imbalances as of December 31, 2011 and 2010.

We recognize revenue when crude oil and natural gas quantities are delivered to or collected by the respective purchaser. Title to the produced quantities transfers to the purchaser at the time the purchaser receives or collects the quantities. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for crude oil and natural gas purchases within thirty-five days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that accounts receivable from those purchasers are collectible.

As previously discussed, we sold our crude oil and natural gas production to several independent purchasers. We had sales of 10% or more of our total oil and natural gas sales revenue to four customers which represented 61% of total oil and natural gas sales revenue for the year ended December 31, 2011. We had sales of 10% or more of our total oil and natural gas sales revenue to four customers representing 61% of total oil and natural gas sales revenue for the year ended December 31, 2010.

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Share-Based Compensation

We measure and record compensation expense for all share-based payment awards to employees and directors based on estimated fair values. Additionally, compensation costs for share-based awards are recognized over the requisite grant-date service period based on the grant-date fair value. There were no outstanding share-based awards during 2011 or 2010.

Financial Instruments

The Company's financial instruments are cash, certificates of deposit, accounts receivable and payable and long-term debt. Management believes the fair values of these instruments, with the exception of the long-term debt, approximate the carrying values, due to the short-term nature of the instruments. Management believes the fair value of long-term debt also reasonably approximates its carrying value, based on expected cash flows and interest rates.

Earnings Per Share

Basic earnings per share is computed based on the weighted average number of shares of common stock outstanding during the year. Diluted earnings per share takes common stock equivalents (such as options and warrants) into consideration. The Company had no common stock equivalents in 2011 or 2010.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

OIL AND NATURAL GAS PROPERTIES

The Company made no purchases of oil and natural gas properties during the years ended December 31, 2011 and 2010. The Company drilled a successful developmental well in New Mexico, for which the net cost to the Company was approximately $4,200,000 as of December 31, 2011.

2. RELATED PARTY TRANSACTIONS

The Company leases office space from its president. Rent expense for this month-to-month lease was $30,000 for each of the years ended December 31, 2011 and 2010, respectively. The Company also paid Roger Bryant, a director, $5,000 in consulting fees for services in 2010. The Company also paid Karl Reimers, a director, $500 in consulting fees in 2010.

3. LINE OF CREDIT

The Company has a line of credit with a bank with a borrowing base of $8,500,000 at December 31, 2011. The agreement requires monthly interest-only payments until maturity on October 18, 2014. The interest rate is based on a LIBOR or Prime option. The Prime option provides for the interest rate to be prime plus a margin ranging between 1.75% and 2.25% and the LIBOR option to be the 3-month LIBOR rate plus a margin ranging between 2.75% and 3.25%, both depending on the borrowing base usage. Currently, we have elected the LIBOR interest rate option in which our interest rate was approximately 3.50% as of December 31, 2011. The commitment fee is .50% of the unused borrowing base. The line of credit provides for certain financial covenants and ratios which include a current ratio, leverage ratio, and interest coverage ratio requirements. We were in compliance with our covenants as of December 31, 2011 and 2010. The line of credit is collateralized by substantially all of our oil and gas properties and is personally guaranteed by our President and CEO.

4. INCOME TAXES

Our provision for income taxes comprised the following (expense) benefit during the years ended December 31:

	2011	2010
Current:		
Federal	$ —	$ (194,000)
State	(12,000)	(51,000)
Total current	(12,000)	(245,000)
Deferred:		
Federal	(317,000)	(185,000)
State	(58,000)	(20,000)
Total deferred	(375,000)	(205,000)
Total income tax provision	$ (387,000)	$ (450,000)

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Total income tax (expense) benefit differed from the amounts computed by applying the U.S. Federal statutory tax rates and estimated state rates to pre-tax income for the years ended December 31, 2011 and 2010 as follows:

	2011	2010
Statutory rate	(34%)	(34%)
State taxes, net of federal benefit	(5%)	(3%)
Changes in enacted rates	—	—
Other differences	—	1%
Effective rate	(39%)	(36%)

Other differences relate to permanent differences, primarily tax depletion in excess of basis.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and tax bases of assets and liabilities.

Significant components of net deferred tax assets and liabilities are:

	December 31,	
	2011	2010
Deferred tax assets:		
Asset retirement obligation	$ 327,000	$ 297,000
Allowance for doubtful accounts	36,000	36,000
Accrued compensation and other	22,000	63,000
Net operating loss carryover	458,000	—
Total deferred tax assets	843,000	396,000
Deferred tax liability:		
Difference in depreciation, depletion and capitalization methods – oil and gas properties	(2,252,000)	(1,330,000)
Total deferred tax liabilities	(2,252,000)	(1,330,000)
Net deferred tax liability	$ (1,409,000)	$ (934,000)

Our net deferred tax assets and liabilities are recorded as follows:

	2011	2010
Current asset	$ 58,000	$ 99,000
Non-current liability	(1,467,000)	(1,033,000)
Total	$ (1,409,000)	$ (934,000)

The Company had no material uncertain tax positions as of December 31, 2011 and 2010.

The Company's policy regarding income tax interest and penalties is to expense those items as general and administrative expense but to identify them for tax purposes. During the years ended December 31, 2011 and 2010, there were no significant income tax interest and penalty items in the income statement, nor as a liability on the balance sheet.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Generally, the Company is no longer subject to U.S. federal or state income tax examination by tax authorities for years before 2007. The Company is not currently involved in any income tax examinations.

At December 31, 2011, we had available for U.S. federal income tax reporting purposes, net operating loss carryforwards (NOL) for regular tax purposes of approximately $1.3 million which expires in 2031.

5. STOCKHOLDERS' EQUITY

During the year ended December 31, 2011, the Company repurchased 94,000 of its common shares for a total cost of $358,550. During the year ended December 31, 2010, the Company repurchased 293,000 of its common shares for a total cost of $830,952.

The Company approved a stock warrant dividend of one warrant per one common share outstanding in the fourth quarter of 2011 subject to setting the record date and registering the warrants. The warrants have an exercise price of $4.00 and are exercisable over 6 years from the record date. The Company has the right to call the warrants in the future if the market price of the common stock exceeds 150% of the exercise price of the warrant ($6.00). The fair value of the warrants will be calculated on the record date and the fair value will be reclassified from retained earnings to additional paid-in capital.

6. ENVIRONMENTAL ISSUES

The Company is engaged in oil and natural gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures as they relate to the drilling of oil and natural gas wells and the operation thereof. In the Company's acquisition of existing or previously drilled well bores, the Company may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental clean up or restoration, the liability to cure such a violation could fall upon the Company. No claim has been made, nor is the Company aware of any liability which the Company may have, as it relates to any environmental cleanup, restoration or the violation of any rules or regulations relating thereto.

7. COMMITMENTS

As of December 31, 2011 and 2010, the Company had a $30,000 outstanding standby letter of credit in favor of the State of Wyoming as a plugging bond. The letter of credit is collateralized by the Company's line of credit with Citibank.

In 2001, the Company entered into an executive employment agreement with its President and Chief Executive Officer. The agreement provides for his retention, if the Company should have a change in control, at set percentages of his then salary and bonus for a term of at least three years.

On October 24, 2008, our Board of Directors approved a Performance Based Bonus Program (the "Bonus Program") for our President and Chief Executive Officer. The Bonus Program is calculated and paid annually based on four performance parameters: 1) annual reserve additions from drilling and acquisitions; 2) growth in annual production; 3) growth in annual year over year earnings (before taxes and bonus); and 4) other notable achievements as the Board may recognize from time to time which are not easily

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

quantifiable in the first three parameters. Bonus awards of up to 50% of annual base salary may be achieved in each of the first three categories and up to 10% in the fourth category provided that the maximum bonus award for any year may not exceed 150% of base salary which is currently $250,000. We awarded approximately $57,000 and $175,000 to our President and Chief Executive Officer under the Bonus Program in 2011 and 2010, respectively.

8. Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following table sets forth certain information with respect to the oil and natural gas producing activities of the Company:

	Years Ended December 31, 2011	2010
Costs incurred in oil and natural gas producing activities:		
Acquisition of unproved properties	$ —	$ —
Acquisition of proved properties	—	—
Exploration costs	—	—
Development costs	4,847,996	523,882
Total costs incurred	$ 4,847,996	$ 523,882

The following table summarizes changes in the estimates of the Company's net interest in total proved reserves of crude oil and condensate and natural gas and liquids, all of which are domestic reserves. There can be no assurance that such estimates will not be materially revised in subsequent periods.

	Oil (Barrels)	Gas (MCF)
Balance, January 1, 2010	1,203,183	3,458,707
Revisions of previous estimates	43,346	(667,733)
Production	(77,574)	(152,318)
Balance, December 31, 2010	1,168,955	2,638,656
Revisions of previous estimates	(20,872)	(430,706)
Extensions and discoveries	123,526	204,740
Sale of reserves	(1,950)	—
Production	(69,395)	(143,142)
Balance, December 31, 2011	1,200,264	2,269,548
Proved developed reserves, December 31, 2011	980,341	1,922,181
Proved developed reserves, December 31, 2010	885,658	2,181,689

Proved oil and natural gas reserves are the estimated quantities of crude oil, condensate, 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. Proved developed oil and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The above estimated net interests in proved reserves are based upon subjective engineering judgments and may be affected by the limitations inherent in such estimation. The process of estimating reserves is subject to continual revision as additional information becomes available as a result of drilling, testing, reservoir studies and production history, and market prices for oil and natural gas. Significant fluctuations in market prices have a direct impact on recoverability and will result in changes in estimated recoverable reserves without regard to actual increases or decreases in reserves in place.

FIELDPOINT PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Year Ended December 31, 2010

The average natural gas price attributable to our proved reserves increased from $3.59 per Mcf at December 31, 2009 to $4.31 at December 31, 2010. The average price of oil per barrel was approximately $76.78 at December 31, 2010 compared to $58.92 at December 31, 2009. The increase in oil prices was the primary reason for the increased oil quantities listed under revisions of previous estimates. The decrease in natural gas quantities was primarily due to a higher decline rate for the Stauss property based on evaluation of more production history and a steeper decline rate which resulted in an impairment charge in 2010.

Year Ended December 31, 2011

The average natural gas price attributable to our proved reserves was $4.03 per Mcf at December 31, 2011. The average oil price attributable to our proved reserves was $94.69 per barrel at December 31, 2011. The revision of estimates of natural gas quantities is primarily due to the South Vacuum well ceasing production in December 2011, which resulted in an impairment charge.

9. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED)

The standardized measure of discounted future net cash flows at December 31, 2011 and 2010, relating to proved oil and natural gas reserves is set forth below. The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with prescribed accounting and SEC standards. Future cash inflows were computed by applying the unweighted, arithmetic average of the closing price on the first day of each month for the 12-month period prior to December 31, 2011 and 2010, to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved.

Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of our oil and natural gas properties.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The estimated cash flows from future production of proved reserves were prepared on the basis of average prices received in 2011 and 2010.

	Years Ended December 31, (in thousands) 2011	2010
Future cash inflows	$ 118,737	$ 97,748
Future production costs	(42,213)	(41,817)
Future development cost	(5,148)	(6,653)
Future income taxes	(21,656)	(14,533)
Future net cash flows	49,720	34,745
10% annual discount	(23,807)	(17,217)
Standardized measure of discounted future net cash flows	$ 25,913	$ 17,528

The following are the principal sources of change in the standardized measure of discounted future net cash flows, in thousands:

	Years Ended December 31, 2011	2010
Balance, beginning of year	$ 17,528	$ 15,998
Sales of oil and natural gas produced, net of production costs	(4,662)	(4,171)
Sale of reserves	(51)	—
Extensions and discoveries	4,112	—
Net changes in prices and production costs	12,700	8,461
Net changes in future development costs	1,137	(2,425)
Revisions and other changes	(3,659)	(1,028)
Accretion of discount	2,621	2,307
Net change in income taxes	(3,813)	(1,614)
Balance, end of year	$ 25,913	$ 17,528

Exhibit 23

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statement (No. 333-178126) on Form S-3 of FieldPoint Petroleum Corporation and subsidiaries of our report dated March 20, 2012, relating to our audits of the consolidated financial statements, which appear in this Annual Report on Form 10-K of FieldPoint Petroleum and subsidiaries for the years ended December 31, 2011 and 2010.

/s/ Hein & Associates LLP
Dallas, Texas

March 20, 2012

Exhibit 31

CERTIFICATION

I, Ray Reaves, certify that:

1. I have reviewed this Annual Report on Form 10-K of FieldPoint Petroleum Corporation;

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

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

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

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

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

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

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

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

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

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

Date March 20, 2012

/s/ Ray Reaves
Ray Reaves, Chief Executive Officer and
Chief Financial Officer

Exhibit 32

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

In connection with the Quarterly Report of FieldPoint Petroleum Corporation (the "Company") on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ray Reaves, Chief Executive Officer and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

/s/ Ray Reaves
Ray Reaves
Chief Executive Officer and
Chief Financial Officer
March 20, 2012

Exhibit 99.3

RESERVE AND ECONOMIC EVALUATION
FIELDPOINT PETROLEUM CORPORATION
AS OF JANUARY 1, 2012

PREPARED FOR

RAY REAVES

FEBRUARY 14, 2012

FLETCHER LEWIS ENGINEERING, INC.

fletcher lewis engineering, inc.
5001 N. PENNSYLVANIA, SUITE 300
PENN PARK OFFICE CENTER
OKLAHOMA CITY, OKLAHOMA 73112
(405) 840-5675

February 14, 2012

Fieldpoint Petroleum Corporation
Mr. Ray Reaves
1703 Edelweiss Dr.
Cedar Park, TX 78613

RE: Reserve and Economic Evaluation
Fieldpoint Petroleum Corporation
SEC Case Economics
As of January 1, 2012

Mr. Reaves:

As requested, I have prepared the Reserve and Economic Evaluation of various oil and gas properties owned by Fieldpoint Petroleum Corporation as of January 1, 2012. These evaluations consist of sixty-four (64) properties located throughout Oklahoma and Hemphill County, Texas. Many of these properties contain numerous wells with Behind-Pipe completions, additional drilling development potential and additional waterflood reserves. This report contains seventy-four (74) evaluations consisting of sixty-four (64) Proved Developed Producing properties, eight (8) Behind-Pipe properties and two (2) Proved Undeveloped properties. The two Proved Undeveloped properties consist of three (3) increased density wells to be drilled.

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The Future Net Reserves and Future Net Revenue of the evaluated Fieldpoint Petroleum Corporation interests as of January 1, 2012, are as follows:

	NET OIL (BBLS)	NET GAS (MCF)	FUTURE NET REVENUE $	DISCOUNTED PRESENT WORTH 10% $
Proved Developed Producing	66,303	107,817	4,327,076	2,653,252
Behind-Pipe	114,138	373,000	8,672,234	3,948,321
Proved Undeveloped	13,753	11,287	1,057,363	479,144
Summary Proved	194,194	492,104	14,056,673	7,080,717

Following this report is a table listing the individual well or lease locations and the evaluated Working Interest and Net Revenue Interest. Following is a table listing the individual and summary Future Net Reserves and Future Net Revenue as of January 1, 2012. Also following this report are the individual production and economic projections of each of these wells and their summaries.

RESERVE CATEGORIES

The reserves were assigned as Producing, Possible and Probable. There may be some variation on the individual reserve entity but the aggregate of the reserves were multiple entities should adhere to the required probabilities.

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The reserves are estimated and anticipated to be recovered from known accumulations from a given date forward. These are based on the analysis of drilling, geological, geophysical and engineering data with the use of established technology under specified economic conditions which are generally accepted as being reasonable.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. There is at least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved reserves.

Probable reserves are those additional reserves are less certain to be recovered than Proved reserves. There is at least a 50% probability that the quantity actually recovered will equal or exceed the sum of the estimated Probable reserves.

Possible reserves are those additional reserves that are less certain to be recovered than Probable reserves. There is at least 10% probability that the quantity actually recovered will equal or exceed the sum of the estimated Possible reserves.

RESERVE DETERMINATION

All of the evaluated properties are disbursed by Ram Operating Company, although only slightly more than half are operated. The public reported production for the wells are available through August 1, 2011, however there are many errors and inconsistencies in the public data. The Ram Operating Company properties have production histories available by the remittances through October 2011. The outside operated properties had production by the remittances through August 2011.

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SEC Case
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The Proved Developed Producing properties were assigned reserves by assigning the latest available production rates and then extrapolating each property's historical production decline until its economic limit was reached.

The production data available through public services was often missing several months with a greater amount of errors in the more recent production. These public figures were compared to the volumes from the remittances, if the data did not agree the production histories were based on the remittance data. Beginning June 2011, the sales remittance volumes changed on many of the gas wells changed from total gas to a reduced process gas volume (usually 50%-75% of the total gas) with associated sales of plant products. If there was consistent public data to compare with the processed gas, the public reported data was used with a calculated gas price from the total sales and production. For those properties with reduced gas volumes and no reliable public production numbers, the decline was based on the reduced gas volumes but with a higher gas price incorporating the plant products as part of the gas price.

The Mount Gilcrease Unit has significant Behind-Pipe reserves located throughout the unit. Productive Calvin, Thurman, Earlsboro and Lower Booch sands are found in numerous wells; nineteen of these wells have been completed in these sands, although it should be noted that in these wellbores, additional Behind-Pipe sands still exist. Behind-Pipe Lower Booch reserves were assigned to twenty-five (25) of the remaining forty-

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seven (47) wellbores on a ten acre tract basis and on ten (10) of the fifteen (15) wellbores for the Calvin, Thurman and Earlsboro sands on a 40 acre tract basis; utilizing the porosities, water saturation and feet of net pay exhibited in the well logs, a 90% gas recovery factor for the Calvin, Thurman and Earlsboro zones and a 20% recovery factor for the Booch zones. These wells were scheduled to be completed in 2015 to 2019. These Behind-Pipe reserves are presented in two evaluations.

An additional two Gilcrease zones have been found to be productive in a recent recompletion and these same two zones are Behind-Pipe on the Britt Lease. Reserves were determined volumetrically utilizing the average net pay; porosity and water saturation exhibited though the area and a 15% recovery factor with a ten acre drainage per Behind-Pipe well. It is estimated that there are two wells with Behind-Pipe Gilcrease intervals in this lease. Reserves were assigned using an average initial production rate and decline to produce the volumetric reserves of each well and the recompletions are scheduled for January 2014.

The Butler property has an additional well with Behind-Pipe Gilcrease, Booch, Thurman and Earlsboro reserves. Gas reserves were assigned the Thurman and Earlsboro on a 40 acre basis utilizing the exhibited net pays, porosities and water saturations and utilizing a 90% recovery factor and oil reserves for the Gilcrease and Booch on a ten acre basis utilizing a 20% recovery factor. This recompletion was scheduled for January 2014. There is also an additional drilling location to be completed in the Gilcrease, Booch and Senora formations that was assigned Proved Undeveloped reserves. Reserves were determined volumetrically and by offset analogous production.

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The Nan #1—30 has Behind-Pipe Booch and Thurman and the Nan #2—30 has Behind-Pipe Thurman. The Nan #1—30 was scheduled to complete the Behind-Pipe zones in January 2013, and the Nan #2—30 was scheduled to complete the Behind—Pipe zone in April 2013.

The Provence A lease has six Behind-Pipe Cromwell zones which are scheduled to be recompleted in July 2013, 2014 and 2015. There are also an additional two drilling locations which were scheduled to be drilled July 2013 and were assigned Proved Undeveloped reserves. These reserves were assigned based on analogous production.

Reserve estimates are only as reliable as the amount and quality of data that is available. The reserves assigned were developed with accepted engineering and evaluation principles, and are believed to be reasonable; however, the reserves should be accepted with the understanding that additional information subsequent to the date of this report might require their revision.

ECONOMIC ANALYSIS

The SEC rules require an average oil and gas price to be used that is derived from the first of the month oil and gas spot market prices as of the first of the month beginning in January through December 2011. The average posted price used was $89.75 per barrel and $3.93 per MCF. The individual first of the month prices and average prices are as follows:

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	OIL PRICE	GAS PRICE
JAN 1, 2011	$ 85.70	$ 4.10
FEB 1, 2011	$ 85.09	$ 4.31
MAR 1, 2011	$ 93.96	$ 3.66
APR 1, 2011	$ 102.30	$ 4.13
MAY 1, 2011	$ 108.38	$ 4.15
JUN 1, 2011	$ 94.70	$ 4.12
JUL 1, 2011	$ 89.33	$ 4.20
AUG 1, 2011	$ 89.29	$ 4.21
SEP 1, 2011	$ 83.33	$ 3.78
OCT 1, 2011	$ 73.60	$ 3.66
NOV 1, 2011	$ 77.30	$ 3.45
DEC 1, 2011	$ 94.01	$ 3.39
AVERAGE	$ 89.75	$ 3.93

The monthly oil price actually received was $3.44 per barrel above the posted prices and an oil price of $93.19 was used for these properties. This price was held constant for the life of the evaluation.

This average posted gas price was then adjusted by the individual remittances (differential) to assign the average price for each well. Plant products were incorporated into the gas price. For those properties in which only the processed gas volumes were available, incorporating the plant products resulted in high gas prices. These gas prices were held constant for the life of this evaluation.

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Operating expenses were examined and the average historical operating expenses were calculated for each property utilizing Joint Interest Billings supplied to Fieldpoint Petroleum. The Behind-Pipe and Proved Undeveloped properties were assigned operating expenses typical to the formation and area. These operating expenses were held constant throughout the life of the evaluation.

The estimated costs for completing the Behind-Pipe zones in the Mount Gilcrease Unit are $15,000.00 per Lower Booch completion and $15,000.00 per well for the shallower gas completions (the shallower completions will require additional cementing costs) for a single zone completion. The estimated costs for to recomplete the Nan #1 is $18,000.00 and the Nan #2 is $55,000.00. The Butler Behind-Pipe completion is $25,000.00, with $60,000.00 to drill the additional well. The Provence A Behind-Pipe recompletion costs are $15,000.00 per well with $35,000.00 to drill and complete each of the two proposed wells.

Applicable Severance and Ad Valorum Taxes have been considered in the economic evaluations. No consideration has been given to depreciation or Federal or State Income Taxes. Also, no future value was given for salvage equipment nor future costs to plug or abandon these wells (in most cases the salvage value is equal to plugging costs), for this evaluation.

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GENERAL

In evaluating the information available for this appraisal only the engineering data was evaluated with no potential legal or accounting considerations. The conclusions expressed were derived using accepted and sound engineering methods; however, inherent uncertainties in interpretations of engineering data do exist and the conclusions represent only informed professional judgment.

The basic data and computations are not in this report, but are available for inspection and study by authorized parties. Should any additional information be required, please do not hesitate to call.

Sincerely,

Fletcher Lewis, P.E.

Fieldpoint - report 2012 sec

GENERAL INFORMATION
FIELDPOINT PETROLEUM CORPORATION PROPERTIES

WELL NAME	LOCATION	COUNTY	WORKING INTEREST %	NET REVENUE INTEREST %	
ALEXANDER #1-3	3 B&B SUR	HEMPHILL	0.0585	0.0180	
BARGER #1-11	11-9N-11W	CADDO	0.1953	0.1587	
BARGER #2-1 1	11-9N-11W	CADDO	0.1953	0.1485	
BARROW #1-31	31-10N-11W	CADDO	0.0974	0.0842	
BARROW #2-31	31-10N-11W	CADDO	0.3896	0.3367	
BRITT LEASE	20-4N-7E	PONTOTOC	25.0000	18.5797	
BRITT 10 LEASE	20-4N-7E	PONTOTOC	25.0000	20.3125	
LOWINDA BROWN #6-8	7-1N-8E	COAL	21.8750	9.5703	OIL
				19.5703	GAS
BUTLER LEASE	30-5N-8E	PONTOTOC	25.0000	20.9003	
CHANUTE LEASE	36-5N-7E	PONTOTOC	25.0000	21.8750	
CITY OF ARDMORE #1-3	3-5S-2E	CARTER	0.8536	0.6651	
DEVAUGHAN #1-31	31-10N-11W	CADDO	0.3896	0.3367	
DIAMOND LEASE	30- 5N- 8E	PONTOTOC	25.0000	20.8840	
ECKROAT #1-15		OKLAHOMA	16.7637	13.4109	
FRANK EDGE #1-11	11-9N-11W	CADDO	0.1953	0.1587	
IDA EDGE #1-11	11-9N-11W	CADDO	0.1953	0.1587	
FOLMAR #1-27	27-12N-2W	OKLAHOMA	17.1875	14.9274	
DORA HELMS #3-2	2-1N-7E	OKLAHOMA	18.8423	15.7478	
DORA HELMS #4-2	2-1N-7E	PONTOTOC	18.8423	17.1831	
HENDRICKS #1-15	15-6N-9W	CADDO	0.1094	0.0634	
HENDRICKS TRUST #1-27	27-12N-2W	OKLAHOMA	25.0000	20.3125	
IDA HOLLIE #1-20	20-7N-23E	LEFLORE	0.5207	0.4232	
IDA HOLLIE #2-20	20-7N-23E	LEFLORE	0.5207	0.4232	
				9.5704	OIL
E E HOUSE #1-12	12-1N-7E	PONTOTOC	21.8750	19.1407	GAS
E E HOUSE #10-12	12-1N-7E	PONTOTOC	21.8750	9.5704	OIL
				21.8750	GAS
JESSIE #1-24	24-12N-13W	CADDO	0.4035	0.3531	
JESSIE TOWNSITE #1-2	2-1N-7E	PONTOTOC	18.8064	17.0021	
KOLB #1-15	15-12N-2W	OKLAHOMA	21.8750	17.7734	

GENERAL INFORMATION
FIELDPOINT PETROLEUM CORPORATION PROPERTIES

WELL NAME	LOCATION	COUNTY	WORKING INTEREST %	NET REVENUE INTEREST %
LEWIS #1-11	11-5N-2W	MCCLAIN	11.2386	9.6085
LIVELY #1-6	6-5N-20E	LATIMER	0.3906	0.2930
MCBRIDE #1-8	8-9N-11W	CADDO	0.0977	0.0794
MCCURTAIN #1-1	1-1N-7E	PONTOTOC	20.5625	17.9922
MCDONALD LEASE	19-5N-8E	PONTOTOC	25.0000	21.8750
MCINTOSH #1-11	11-4N-9W	COMANCHE	0.1297	0.0979
MOONEY #1-29	29-6N-2W	MCCLAIN	17.1875	13.6211
MOUNT GILCREASE #3-12	36-5N-7E	PONTOTOC	25.0000	21.8750
MOUNT GILCREASE #8-6	36-5N-7E	PONTOTOC	25.0000	21.8750
MOUNT GILCREASE #8-9	36-5N-7E	PONTOTOC	25.0000	21.8750
MOUNT GILCREASE UNIT	25,26&35-5N-7E	PONTOTOC	25.0000	21.7707
MUSE #1-33	33-2N-7E	PONTOTOC	6.2500	5.4688
NAN #1-30	30-5N-8E	PONTOTOC	25.0000	19.8242
NAN #2-30	30-5N-8E	PONTOTOC	25.0000	19.8242
NORTHEAST FITTS UNIT	22 & 23-2N-7E	PONTOTOC	0.0009	.00075
PARMENTER #2-4	4-18N-15W	DEWEY	2.8438	2.2395
K O PAYNE #1-10	10-17N-12W	BLAINE	1.1349	0.9431
PETTYJOHN B	1-1N-7E	PONTOTOC	25.0000	20.5078
CE PETTYJOHN	1-1N-7E	PONTOTOC	25.0000	20.5078
GLADYS PETTYJOHN	1-1N-7E	PONTOTOC	25.0000	21.0937
POLLARD #2-31	31-19N-4W	LOGAN	4.5921	3.7411
POWELL D #1-22	22-7N-8W	GRADY	3.1250	2.5000
PROVENCE #1-2	2-1N-7E	PONTOTOC	25.0000	20.8733
PROVENCE A LEASE	2-1N-7E	PONTOTOC	25.0000	20.8733
ROSSER #1-31	31-10N-11W	CADDO	0.0974	0.0842
ROZIE #1-31	31-10N-11W	CADDO	0.0974	0.0760
SANDY A #1-8	8-1N-8E	COAL	4.9781	4.0771
SHAW #1-11	11-9N-11W	CADDO	0.1953	0.1587
R W SIMPSON #1-12	12-1N-7E	PONTOTOC	21.8750	19.1407
TEX #1-14	14-4N-16E	PITTSBURG	0.8203	0.6768

fieldpoint 2011 - TABLESGENERAL

GENERAL INFORMATION
FIELDPOINT PETROLEUM CORPORATION PROPERTIES

WELL NAME	LOCATION	COUNTY	WORKING INTEREST %	NET REVENUE INTEREST %
THOMAS #1-20	20-2N-7E	PONTOTOC	21.8750	18.8241
GEORGE THOMPSON #1-1	1-1N-7E	PONTOTOC	15.1563	12.3145
PHARR THOMPSON #1-2	2-1N-7E	PONTOTOC	5.6989	4.9680
THOMPSON HEIRS #4 & 5-1	1-1N-7E	PONTOTOC	17.5938	15.0108
TROGDEN #1-15	15-6N-9W	CADDO	0.0936	0.0708
VIRGINIA #1-31	31-10N-11W	CADDO	0.0974	0.0676

fieldpoint 2011 - TABLESGENERAL

RESERVE AND ECONOMIC EVALUATION
FIELDPOINT PETROLEUM CORPORATION
AS OF JANUARY 1, 2012

NAME	STATUS	NET OIL BBLS	NET GAS MCF	FUTURE NET CASHFLOW	DISCOUNTED 10% $
ALEXANDER #1-3	PDP	0	0	0	0
BARGER #1-11	PDP	4	238	644	470
BARGER #2-11	PDP	10	72	527	408
BARROW #1-31	PDP	5	314	1,007	720
BARROW #2-31	PDP	6	485	1,365	1,065
BRITT LEASE	PDP	0	0	0	0
BRITT LEASE	BHP	6,799	0	541,004	278,160
BRITT 10 LEASE	PDP	0	0	0	0
LOWINDA BROWN #6-8	PDP	562	6,144	24,764	19,712
BUTLER LEASE	PDP	164	316	2,799	2,534
	BHP	564	61,238	111,878	78,523
	PUD	9,405	11,287	766,419	307,632
CHANUTE LEASE	PDP	1,993	0	109,133	67,283
CITY OF ARDMORE #1-3	PDP	0	1,081	1,204	1,035
DEVAUGHAN #1-31	PDP	6	313	954	796
DIAMOND LEASE	PDP	19,952	0	1,378,232	830,900
ECKROAT #1-15	PDP	0	0	0	0
FRANK EDGE #1-11	PDP	3	53	107	94
IDA EDGE #1-11	PDP	8	323	1,136	817
FOLMAR #1-27	PDP	4,813	0	344,502	202,328
DORA HELMS #3-2	PDP	203	3,154	26,187	17,961
DORA HELMS #4-2	PDP	0	3,433	18,923	13,026
HENDRICKS #1-15	PDP	0	53	44	40
HENDRICKS TRUST #1-27	PDP	0	0	0	0
IDA HOLLIE #1-20	PDP	0	1,321	2,855	2,357
IDA HOLLIE #2-20	PDP	0	0	0	0
E E HOUSE #1-12	PDP	0	364	172	164
E E HOUSE #10-12	PDP	0	12,855	72,186	44,978
JESSIE #1-24	PDP	0	503	550	451
JESSIE TOWNSITE #1-2	PDP	5,093	0	388,438	218,261
KOLB #1-15	PDP	0	0	0	0
LEWIS #1-11	PDP	565	20,341	104,451	52,760

RESERVE AND ECONOMIC EVALUATION
FIELDPOINT PETROLEUM CORPORATION
AS OF JANUARY 1, 2012

NAME	STATUS	NET OIL BBLS	NET GAS MCF	FUTURE NET CASHFLOW	DISCOUNTED 10% $
LIVELY #1-6	PDP	0	639	1,217	1,037
MCBRIDE #1-8	PDP	0	0	0	0
MCCURTAIN #1-1	PDP	12	3	37	37
MCDONALD LEASE	PDP	0	0	0	0
	BHP	6,264	16,615	510,525	308,956
MCINTOSH #1-11	PDP	0	72	78	72
MOONEY #1-29	PDP	1,581	0	88,325	47,228
MOUNT GILCREASE #3-12	PDP	0	32,584	28,413	19,864
MOUNT GILCREASE #8-6	PDP	0	0	0	0
MOUNT GILCREASE #8-9	PDP	0	0	0	0
MOUNT GILCREASE UNIT	PDP	12,211	0	384,068	306,650
	BHP	0	276,228	310,865	210,854
	BHP	84,869	0	6,113,026	2,432,059
MUSE #1-33	PDP	1,068	0	73,483	40,049
NAN #1-30	PDP	1,010	0	36,595	26,612
	BHP	0	18,919	11,764	9,470
NAN #2-30	BHP	2,974	0	229,259	158,149
NORTHEAST FITTS UNIT	PDP	79	0	2,887	2,417
PARMENTER #2-4	PDP	8	967	2,551	1,898
K O PAYNE #1-10	PDP	0	0	0	0
PETTYJOHN B	PDP	0	0	0	0
CE PETTYJOHN	PDP	208	7,711	17,511	13,545
GLADYS PETTYJOHN	PDP	0	0	0	0
POLLARD #2-31	PDP	139	2,893	16,403	10,004
POWELL D #1-22	PDP	0	2,323	3,792	2,990
PROVENCE #1-2	PDP	0	0	0	0
PROVENCE A LEASE	PDP	0	4,700	3,234	2,757
	BHP	12,668	0	843,913	472,150
	PUD	4,348	0	290,944	171,512
ROSSER #1-31	PDP	1	114	295	227
ROZIE #1-31	PDP	2	343	823	600
SANDY A #1-8	PDP	0	0	0	0

RESERVE AND ECONOMIC EVALUATION
FIELDPOINT PETROLEUM CORPORATION
AS OF JANUARY 1, 2012

NAME	STATUS	NET OIL BBLS	NET GAS MCF	FUTURE NET CASHFLOW	DISCOUNTED 10% $
SHAW #1-11	PDP	0	0	0	0
R W SIMPSON #1-12	PDP	0	0	0	0
TEX #1-14	PDP	0	2,340	2,442	1,721
THOMAS #1-20	PDP	11,068	0	829,032	486,052
GEORGE THOMPSON #1-1	PDP	2,918	0	200,803	109,748
PHARR THOMPSON #1-2	PDP	164	1,496	12,663	8,104
THOMPSON HEIRS #4 & 5-1	PDP	2,441	0	141,774	93,106
TROGDEN #1-15	PDP	0	62	24	19
VIRGINIA #1-31	PDP	2	208	446	356
PROVED DEVELOPED PRODUCING		**66,303**	**107,817**	**4,327,076**	**2,653,252**
BEHIND-PIPE		**114,138**	**373,000**	**8,672,234**	**3,948,321**
PROVED UNDEVELOPED		**13,753**	**11,287**	**1,057,363**	**479,144**
SUMMARY PROVED		**194,194**	**492,104**	**14,056,673**	**7,080,717**

fieldpoint 2012 - TABLES

AS OF JAN 1, 2012 RESERVES AND ECONOMICS
Run Date 2/14/2012 22:11

INTERESTS AND DATE FIRST EFFECTIVE

SUMMARY

COST LIQUID GAS DATE

PRESENT WORTH M$	
5.000	9660.665
10.000	7080.717
15.000	5452.294
20.000	4362.875
25.000	3599.043

	WELL GROSS	COUNT NET	API OR BTU	BASE PRICE	TRANS. CHARGE	PROD. TAXES	ADVAL TAXES	PRICES BEGIN	PRICES ENDING	PRICES LIFE WT	CF/BBL BL/MMCF	GROSS CUMULATIVE	R
OIL	155.	33.29						93.19	93.19	93.19	5315.	7863.72	
GAS	36.	4.03						4.45	3.11	2.26	188.	73221.06	
COND	0.	0.00						93.19	93.19	93.19	0.	374.54	

YEAR	GROSS WELL COUNT WELLS/MO	GROSS OIL + COND PROD MBBLS	GROSS GAS PRODUCTION MMCF	NET OIL COND PROD MBBLS	NET GAS PRODUCTION MMCF	EFF OIL & COND PRICE $/BBL	EFFECTIVE GAS PRICE $/MCF	OIL + COND SALES M$	GAS SALES M$	TOTAL SALES M$
2012	106.000	72.313	750.030	7.586	13.967	93.190	4.457	706.920	62.246	769.16
2013	112.000	73.032	717.547	8.714	25.372	93.190	2.898	812.076	73.536	885.61
2014	118.000	80.111	638.446	11.004	37.000	93.190	2.386	1025.418	88.294	1113.71
2015	128.000	82.961	1111.871	12.404	158.014	93.190	1.771	1155.922	279.776	1435.69
2016	135.000	85.614	915.235	13.756	126.604	93.190	1.797	1281.921	227.460	1509.38
2017	139.000	86.304	495.826	14.522	48.477	93.190	2.047	1353.304	99.242	1452.54
2018	139.000	81.961	343.716	15.406	26.784	93.190	2.329	1435.657	62.381	1498.03
2019	131.000	79.518	223.946	15.774	11.600	93.190	3.134	1469.946	36.350	1506.29
2020	75.000	68.901	192.363	13.633	9.535	93.190	3.259	1270.493	31.071	1301.56
2021	73.000	60.511	149.126	11.989	5.984	93.190	3.771	1117.232	22.563	1139.79
2022	66.000	52.784	108.015	10.530	4.627	93.190	4.142	981.284	19.166	1000.45
2023	66.000	45.789	94.344	9.121	4.087	93.190	4.258	849.961	17.405	867.36
2024	63.000	38.860	66.818	7.745	3.408	93.190	4.520	721.797	15.406	737.20
2025	59.000	33.879	26.380	6.791	3.038	93.190	4.563	632.860	13.859	646.71
2026	58.000	29.737	16.832	5.961	2.250	93.190	4.887	555.506	10.995	566.50
SUB TOTAL	139.000	972.275	5850.495	164.935	480.747	93.190	2.204	15370.295	1059.750	16430.04
REMAINDER	55.000	147.888	103.271	29.259	11.357	93.190	4.777	2726.646	54.248	2780.89
TOT 34.6 YR	139.000	1120.163	5953.766	194.194	492.104	93.190	2.264	18096.942	1113.999	19210.94

YEAR	EFFECTIVE WPT TAX M$	NET TOTAL PROD TAXES M$	DIR OPR EXP ADVAL TAX M$	TOT OPR EXP + TAXES M$	OPERATING REVENUE M$	TOT INVEST TANG+INTANG M$	NET CASHFLOW M$	CUM NET CASHFLOW M$	NET C.F. DISC © 10.0 M$	CUM C.F DISC © 10 M$
2012	0.000	55.377	154.500	209.876	559.289	0.000	559.289	559.289	532.254	532.2
2013	0.000	63.697	161.427	225.124	660.488	49.250	611.238	1170.527	525.300	1057.5
2014	0.000	80.127	177.623	257.750	855.962	36.250	819.712	1990.239	642.725	1700.2
2015	0.000	103.303	201.713	305.016	1130.683	48.750	1081.933	3072.172	770.435	2470.7
2016	0.000	108.607	221.092	329.698	1179.682	33.750	1145.932	4218.104	743.771	3214.4
2017	0.000	104.498	227.881	332.379	1120.167	18.750	1101.417	5319.521	649.243	3863.7

2018	0.000	107.783	233.039	340.822	1157.216	18.750	1138.466	6457.988	609.907	4473.6
2019	0.000	108.385	225.907	334.292	1172.004	18.750	1153.254	7611.242	562.237	5035.8
2020	0.000	93.656	137.903	231.559	1070.004	0.000	1070.004	8681.246	474.825	5510.6
2021	0.000	82.013	131.068	213.081	926.714	0.000	926.714	9607.960	373.844	5884.5
2022	0.000	71.973	129.635	201.608	798.842	0.000	798.842	10406.802	292.910	6177.4
2023	0.000	62.398	127.988	190.386	676.980	0.000	676.980	11083.782	225.758	6403.2
2024	0.000	53.035	120.739	173.774	563.429	0.000	563.429	11647.210	170.740	6573.9
2025	0.000	46.524	119.973	166.497	480.222	0.000	480.222	12127.432	132.307	6706.2
2026	0.000	40.761	118.043	158.804	407.697	0.000	407.697	12535.129	102.129	6808.3
SUB TOTAL	0.000	1182.136	2488.530	3670.667	12759.379	224.250	12535.129	12535.129	6808.386	6808.3
REMAINDER	0.000	200.088	1059.262	1259.350	1521.545	0.000	1521.545	14056.673	272.331	7080.7
TOT 34.6 YR	0.000	1382.224	3547.792	4930.017	14280.923	224.250	14056.673	14056.673	7080.717	7080.7

AS OF JAN 1, 2012 RESERVES AND ECONOMICS
Run Date 2/14/2012 21:20

INTERESTS AND DATE FIRST EFFECTIVE
COST LIQUID GAS DATE

SUMMARY
PROVED DEVELOPED PRODUCING

PRESENT WORTH M$	
5.000	3291.514
10.000	2653.252
15.000	2227.703
20.000	1926.247
25.000	1702.434

	WELL GROSS	COUNT NET	API OR BTU	BASE PRICE	TRANS. CHARGE	PROD. TAXES	ADVAL TAXES	PRICES BEGIN	PRICES ENDING	PRICES LIFE WT	CF/BBL BL/MMCF	GROSS CUMULATIVE	R
OIL	115.	23.29						93.19	93.19	93.19	8013.	7863.72	
GAS	25.	1.28						4.45	5.76	4.70	125.	73221.06	
COND	0.	0.00						93.19	93.19	93.19	0.	374.54	

YEAR	GROSS WELL COUNT WELLS/MO	GROSS OIL COND PROD + MBBLS	GROSS GAS PRODUCTION MMCF	NET OIL COND PROD MBBLS	NET GAS PRODUCTION MMCF	EFF OIL & COND PRICE $/BBL	EFFECTIVE GAS PRICE $/MCF	OIL + COND SALES M$	GAS SALES M$	TOTAL SALES M$
2012	106.000	72.313	750.030	7.586	13.967	93.190	4.457	706.920	62.246	769.16
2013	104.000	64.592	652.690	6.976	12.312	93.190	4.350	650.112	53.554	703.66
2014	104.000	57.236	513.496	6.356	11.117	93.190	4.380	592.271	48.693	640.96
2015	101.000	50.853	427.662	5.756	10.001	93.190	4.427	536.395	44.277	580.67
2016	99.000	45.080	372.050	5.241	9.060	93.190	4.457	488.408	40.385	528.79
2017	98.000	40.296	305.897	4.784	7.588	93.190	4.550	445.820	34.522	480.34
2018	94.000	30.065	249.881	4.358	6.656	93.190	4.610	406.094	30.681	436.77
2019	91.000	24.404	196.942	3.974	5.958	93.190	4.652	370.304	27.718	398.02
2020	36.000	17.770	170.997	2.678	5.069	93.190	4.782	249.596	24.238	273.83
2021	34.000	15.880	139.073	2.433	3.884	93.190	4.982	226.708	19.350	246.05
2022	28.000	13.794	102.492	2.186	3.473	93.190	5.010	203.707	17.401	221.10
2023	28.000	12.240	89.996	1.945	3.178	93.190	5.039	181.229	16.014	197.24
2024	27.000	10.541	64.233	1.687	2.868	93.190	5.083	157.252	14.580	171.83
2025	23.000	9.109	23.924	1.496	2.525	93.190	5.179	139.419	13.074	152.49
2026	22.000	8.050	14.499	1.330	1.762	93.190	5.816	123.943	10.248	134.19
SUB TOTAL	106.000	472.223	4073.862	58.785	99.418	93.190	4.597	5478.177	456.981	5935.15
REMAINDER	19.000	47.319	89.120	7.518	8.399	93.190	5.920	700.602	49.723	750.32
TOT 34.6 YR	106.000	519.542	4162.982	66.303	107.817	93.190	4.700	6178.779	506.704	6685.48

YEAR	EFFECTIVE WPT TAX M$	NET TOTAL PROD TAXES M$	DIR OPR EXP ADVAL TAX M$	TOT OPR EXP + TAXES M$	OPERATING REVENUE M$	TOT INVEST TANG+INTANG M$	NET CASHFLOW M$	CUM NET CASHFLOW M$	NET C.F. DISC @ 10.0 M$	CUM C.F. DISC @ 10.0 M$
2012	0.000	55.377	154.500	209.876	559.289	0.000	559.289	559.289	532.254	532.25
2013	0.000	50.623	150.477	201.100	502.566	0.000	502.566	1061.855	434.383	966.63
2014	0.000	46.110	150.323	196.433	444.531	0.000	444.531	1506.386	349.294	1315.93
2015	0.000	41.791	147.113	188.904	391.768	0.000	391.768	1898.155	280.021	1595.95
2016	0.000	38.057	146.392	184.448	344.344	0.000	344.344	2242.499	223.777	1819.72
2017	0.000	34.546	144.081	178.627	301.715	0.000	301.715	2544.214	178.043	1997.77

2018	0.000	31.428	142.739	174.167	262.608	0.000	262.608	2806.822	140.994	2138.76
2019	0.000	28.646	142.107	170.753	227.269	0.000	227.269	3034.091	110.990	2249.75
2020	0.000	19.705	54.503	74.208	199.626	0.000	199.626	3233.717	88.576	2338.33
2021	0.000	17.702	49.268	66.970	179.088	0.000	179.088	3412.805	72.212	2410.54
2022	0.000	15.904	48.635	64.539	156.568	0.000	156.568	3569.373	57.397	2467.94
2023	0.000	14.179	48.588	62.767	134.477	0.000	134.477	3703.850	44.784	2512.72
2024	0.000	12.355	44.539	56.894	114.938	0.000	114.938	3818.787	34.800	2547.52
2025	0.000	10.969	43.773	54.742	97.751	0.000	97.751	3916.538	26.934	2574.45
2026	0.000	9.653	41.843	51.496	82.695	0.000	82.695	3999.233	20.707	2595.16
SUB TOTAL	0.000	427.044	1508.880	1935.925	3999.233	0.000	3999.233	3999.233	2595.166	2595.16
REMAINDER	0.000	53.995	368.487	422.482	327.843	0.000	327.843	4327.076	58.085	2653.25
TOT 34.6 YR	0.000	481.039	1877.367	2358.407	4327.076	0.000	4327.076	4327.076	2653.252	2653.25

AS OF JAN 1, 2012 RESERVES AND ECONOMICS
Run Date 2/14/2012 22:8

INTERESTS AND DATE FIRST EFFECTIVE

COST LIQUID GAS DATE

SUMMARY
BEHIND-PIPE

PRESENT WORTH	M$
5.000	5683.713
10.000	3948.321
15.000	2870.419
20.000	2163.743
25.000	1679.658

	WELL GROSS	COUNT NET	API OR BTU	BASE PRICE	TRANS. CHARGE	PROD. TAXES	ADVAL TAXES	PRICES BEGIN	PRICES ENDING	PRICES LIFE WT	CF/BBL BL/MMCF	GROSS CUMULATIVE	REM
OIL	37.	9.25						0.00	93.19	93.19	3248.	0.00	
GAS	11.	2.75						0.00	1.59	1.58	308.	0.00	1
COND	0.	0.00						0.00	0.00	0.00	0.	0.00	

YEAR	GROSS WELL COUNT WELLS/MO	GROSS OIL + COND PROD MBBLS	GROSS GAS PRODUCTION MMCF	NET OIL COND PROD MBBLS	NET GAS PRODUCTION MMCF	EFF OIL & COND PRICE $/BBL	EFFECTIVE GAS PRICE $/MCF	OIL + COND SALES M$	GAS SALES M$	TOTAL SALES M$
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00
2013	6.000	6.712	64.857	1.377	13.060	93.190	1.530	128.323	19.982	148.30
2014	11.000	18.035	122.817	3.638	25.437	93.190	1.530	339.025	38.919	377.94
2015	24.000	26.084	680.105	5.389	147.155	93.190	1.591	502.201	234.186	736.38
2016	33.000	35.072	539.286	7.374	116.729	93.190	1.592	687.183	185.828	873.01
2017	38.000	41.041	186.225	8.700	40.115	93.190	1.584	810.753	63.536	874.28
2018	42.000	47.365	90.317	10.101	19.393	93.190	1.577	941.312	30.576	971.88
2019	37.000	50.970	23.662	10.934	4.944	93.190	1.530	1018.939	7.564	1026.50
2020	36.000	47.330	18.191	10.161	3.802	93.190	1.530	946.904	5.817	952.72
2021	36.000	41.136	7.037	8.826	1.470	93.190	1.530	822.495	2.249	824.74
2022	35.000	35.768	2.658	7.671	.555	93.190	1.530	714.860	.849	715.71
2023	35.000	30.571	1.627	6.554	.340	93.190	1.530	610.767	.520	611.28
2024	33.000	25.562	0.000	5.482	0.000	93.190	0.000	510.868	0.000	510.86
2025	33.000	22.211	0.000	4.760	0.000	93.190	0.000	443.584	0.000	443.58
2026	33.000	19.307	0.000	4.134	0.000	93.190	0.000	385.247	0.000	385.24
SUB TOTAL	42.000	447.164	1736.782	95.101	373.000	93.190	1.582	8862.462	590.026	9452.48
REMAINDER	33.000	87.632	0.000	19.037	0.000	93.190	0.000	1774.058	0.000	1774.05
TOT 26.6 YR	42.000	534.796	1736.782	114.138	373.000	93.190	1.582	10636.520	590.026	11226.54

YEAR	EFFECTIVE WPT TAX M$	NET TOTAL PROD TAXES M$	DIR OPR EXP ADVAL TAX M$	TOT OPR EXP + TAXES M$	OPERATING REVENUE M$	TOT INVEST TANG+INTANG M$	NET CASHFLOW M$	CUM NET CASHFLOW M$	NET C.F. DISC © 10.0 M$	CUM C.F. DISC © 10. M$
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00
2013	0.000	10.655	9.000	19.655	128.649	31.750	96.899	96.899	81.289	81.28
2014	0.000	27.191	22.200	49.391	328.553	21.250	307.303	404.202	240.556	321.84
2015	0.000	52.981	48.300	101.281	635.106	48.750	586.356	990.559	416.300	738.14
2016	0.000	62.809	68.400	131.209	741.802	33.750	708.052	1698.611	459.249	1197.39
2017	0.000	62.909	77.500	140.409	733.880	18.750	715.130	2413.740	421.286	1618.68
2018	0.000	69.928	84.000	153.928	817.960	18.750	799.210	3212.950	427.799	2046.48

2019	0.000	73.857	77.500	151.357	875.147	18.750	856.397	4069.347	417.305	2463.78
2020	0.000	68.554	77.100	145.654	807.067	0.000	807.067	4876.414	358.166	2821.95
2021	0.000	59.346	75.500	134.846	689.898	0.000	689.898	5566.312	278.347	3100.29
2022	0.000	51.490	74.700	126.190	589.520	0.000	589.520	6155.831	216.170	3316.46
2023	0.000	43.985	73.100	117.085	494.202	0.000	494.202	6650.034	164.877	3481.34
2024	0.000	36.758	69.900	106.658	404.210	0.000	404.210	7054.243	122.522	3603.86
2025	0.000	31.914	69.900	101.814	341.770	0.000	341.770	7396.014	94.172	3698.04
2026	0.000	27.720	69.900	97.620	287.627	0.000	287.627	7683.641	72.060	3770.10
SUB TOTAL	0.000	680.097	897.000	1577.097	7875.391	191.750	7683.641	7683.641	3770.101	3770.10
REMAINDER	0.000	127.640	657.825	785.465	988.593	0.000	988.593	8672.234	178.221	3948.32
TOT 26.6 YR	0.000	807.737	1554.825	2362.562	8863.984	191.750	8672.234	8672.234	3948.321	3948.32

AS OF JAN 1, 2012 RESERVES AND ECONOMICS
Run Date 2/14/2012 21:23

INTERESTS AND DATE FIRST EFFECTIVE
COST LIQUID GAS DATE

SUMMARY
PROVED UNDEVELOPED

PRESENT WORTH M$	
5.000	685.439
10.000	479.144
15.000	354.171
20.000	272.885
25.000	216.951

	WELL GROSS	COUNT NET	API OR BTU	BASE PRICE	TRANS. CHARGE	PROD. TAXES	ADVAL TAXES	PRICES BEGIN	PRICES ENDING	PRICES LIFE WT	CF/BBL BL/MMCF	GROSS CUMULATIVE	R
OIL	3.	.75						0.00	93.19	93.19	820.	0.00	
GAS	0.	0.00						0.00	1.53	1.53	1219.	0.00	
COND	0.	0.00						0.00	0.00	0.00	0.	0.00	

YEAR	GROSS WELL COUNT WELLS/MO	GROSS OIL + COND PROD MBBLS	GROSS GAS PRODUCTION MMCF	NET OIL COND PROD MBBLS	NET GAS PRODUCTION MMCF	EFF OIL & COND PRICE $/BBL	EFFECTIVE GAS PRICE $/MCF	OIL + COND SALES M$	GAS SALES M$	TOTAL SALES M$
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00
2013	2.000	1.728	0.000	.361	0.000	93.190	0.000	33.642	0.000	33.64
2014	3.000	4.840	2.133	1.010	.446	93.190	1.530	94.122	.682	94.80
2015	3.000	6.024	4.104	1.259	.858	93.190	1.530	117.326	1.313	118.63
2016	3.000	5.462	3.899	1.141	.815	93.190	1.530	106.330	1.247	107.57
2017	3.000	4.967	3.704	1.038	.774	93.190	1.530	96.731	1.184	97.91
2018	3.000	4.531	3.518	.947	.735	93.190	1.530	88.251	1.125	89.37
2019	3.000	4.144	3.342	.866	.698	93.190	1.530	80.703	1.068	81.77
2020	3.000	3.801	3.175	.794	.664	93.190	1.530	73.993	1.016	75.00
2021	3.000	3.495	3.016	.730	.630	93.190	1.530	68.029	.964	68.99
2022	3.000	3.222	2.865	.673	.599	93.190	1.530	62.717	.916	63.63
2023	3.000	2.978	2.721	.622	.569	93.190	1.530	57.964	.871	58.83
2024	3.000	2.757	2.585	.576	.540	93.190	1.530	53.677	.826	54.50
2025	3.000	2.559	2.456	.535	.513	93.190	1.530	49.857	.785	50.64
2026	3.000	2.380	2.333	.497	.488	93.190	1.530	46.315	.747	47.06
SUB TOTAL	3.000	52.888	39.851	11.049	8.329	93.190	1.530	1029.656	12.743	1042.40
REMAINDER	3.000	12.937	14.151	2.704	2.958	93.190	1.530	251.986	4.526	256.51
TOT 22.5 YR	3.000	65.825	54.002	13.753	11.287	93.190	1.530	1281.642	17.269	1298.91

YEAR	EFFECTIVE WPT TAX M$	NET TOTAL PROD TAXES M$	DIR OPR EXP ADVAL TAX M$	TOT OPR EXP + TAXES M$	OPERATING REVENUE M$	TOT INVEST TANG+INTANG M$	NET CASHFLOW M$	CUM NET CASHFLOW M$	NET C.F. DISC © 10.0 M$	CUM C.F. DISC © 10. M$
2012	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.00
2013	0.000	2.419	1.950	4.369	29.273	17.500	11.773	11.773	9.628	9.62
2014	0.000	6.826	5.100	11.926	82.878	15.000	67.878	79.651	52.875	62.50
2015	0.000	8.531	6.300	14.831	103.808	0.000	103.808	183.459	74.114	136.61
2016	0.000	7.741	6.300	14.041	93.536	0.000	93.536	276.995	60.745	197.36
2017	0.000	7.043	6.300	13.343	84.572	0.000	84.572	361.567	49.914	247.27
2018	0.000	6.427	6.300	12.727	76.648	0.000	76.648	438.215	41.114	288.38

2019	0.000	5.882	6.300	12.182	69.588	0.000	69.588	507.804	33.942	322.33
2020	0.000	5.397	6.300	11.697	63.312	0.000	63.312	571.116	28.084	350.41
2021	0.000	4.965	6.300	11.265	57.728	0.000	57.728	628.843	23.285	373.69
2022	0.000	4.579	6.300	10.879	52.754	0.000	52.754	681.598	19.343	393.04
2023	0.000	4.234	6.300	10.534	48.301	0.000	48.301	729.898	16.097	409.13
2024	0.000	3.922	6.300	10.222	44.282	0.000	44.282	774.180	13.417	422.55
2025	0.000	3.641	6.300	9.941	40.701	0.000	40.701	814.881	11.201	433.75
2026	0.000	3.388	6.300	9.688	37.374	0.000	37.374	852.255	9.362	443.11
SUB TOTAL	0.000	74.995	82.650	157.645	884.755	32.500	852.255	852.255	443.119	443.11
REMAINDER	0.000	18.453	32.950	51.403	205.108	0.000	205.108	1057.363	36.025	479.14
TOT 22.5 YR	0.000	93.448	115.600	209.048	1089.863	32.500	1057.363	1057.363	479.144	479.14

Exhibit 99.4

PGH
ENGINEERS · CONSULTANTS

FieldPoint Petroleum Corporation

Estimates of
Proved Reserves and Revenues
As of January 1, 2012

SEC Price Guideline Case

Table of Contents

PGH
ENGINEERS · CONSULTANTS

March 2, 2012

Mr. Ray Reaves
FieldPoint Petroleum Corporation
1703 Edelweiss Drive
Cedar Park, Texas 76613

Ref: FieldPoint Petroleum Corporation
Estimates of Proved Reserves and Revenues
As of January 1, 2012
SEC Guideline Case

Dear Mr. Reaves:

In accordance with your request, we have estimated total proved reserves as of January 1, 2012 to FieldPoint Petroleum Corporation's interests in selected oil and gas properties located in Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

As presented in this report, we estimate the net reserves and future net revenue to FieldPoint Petroleum Corporation's interests as follows:

FieldPoint Petroleum Corporation
Total Proved Reserves
As of January 1, 2012

SEC Price Guideline Case	Proved Developed Producing	Proved Behind Pipe	Proved Undeveloped	Total Proved
Estimated Future Net Liquids, MBbl	777.56	22.34	206.17	1,006.07
Estimated Future Net Gas, MMcf	1,087.42	146.81	336.08	1,570.31
Total Future Gross Revenue, M$	76,406.48	2,766.06	20,353.11	99,525.66
Direct Operating Costs, Transportation, and Taxes, M$	31,967.67	554.70	4,761.00	37,283.37
Capital Expenditures, M$	0.00	62.04	4,861.55	4,923.59
Estimated Future Net Revenue ("FNR"), M$	44,438.81	2,149.32	10,730.57	57,318.70
Discounted FNR at 10%, M$	24,902.78	1,301.01	5,123.26	31,327.05
Discounted FNR at 15%, M$	20,769.62	1,077.46	3,665.68	25,512.76

This report has been prepared in accordance with the Society of Petroleum Engineers ("SPE")—Petroleum Resources Management System ("SPE-PRMS"). Risk factors have not been applied to these estimates. A copy of the SPE-PRMS oil and gas reserve definitions for "Proved" reserves (Table 3 to the SPE-PRMS) are attached hereto. This report also conforms to our understanding of the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* promulgated by SPE and the *Guidelines for Application of Definitions for Oil and Gas Reserves* prepared by the Society of Petroleum Evaluation Engineers ("SPEE").

The oil reserves shown are expressed in barrels where one barrel equals 42 US gallons. Gas volumes are expressed in millions of standard cubic feet (MMCF). The reserve and income quantities attributable to the different reserve classifications that are included herein have not been adjusted to reflect the varying degrees of risk associated with them and thus are not comparable.

Future reserves in this report are based on conventional decline curve analysis. The reserves are expressed as property gross and net reserves. Values for reserves are expressed in terms of future net revenue and present worth of future net revenue. Future net revenue is defined as revenue that will accrue to the appraised interests from the production and sale of the estimated net reserves after deducting production taxes, ad valorem taxes, direct lease operating expenses and capital costs. Neither plug and abandonment costs nor salvage was considered in this evaluation. No estimate of Federal Income Tax has been made in this report. Present worth is defined as the future net revenue discounted at the rate shown per year, compounded monthly. The present worth used in this case is 10% per year, compounded monthly.

Prices utilized herein are the average prices of the 12-month prior to the ending date of the period covered by this report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. An average oil price of $96.19 per barrel based on the WTI Cushing, Oklahoma SPOT price and an average gas price of $4.12 per Mcf based on the Henry Hub Gas Cash Market Price were used. No price escalations are included in this report as per SEC regulations. Where applicable, transportation costs have been included and adjustments for heating content, premiums and basis differentials have been applied.

Lease operating expenses are used to establish the economic limit of each property in this report and were not escalated. FieldPoint Petroleum Corporation provided these expenses for the Bass Petroleum, Inc. (part of FieldPoint Petroleum Corporation) operated wells and the non-operated wells. FieldPoint removed COPAS operating charges, capital expenditures and ad valorem taxes from the monthly operating expenses. Severance and ad valorem taxes were also applied as a percentage of gross revenue. A property is considered uneconomic when expenses exceed gross revenues.

Information necessary for the preparation of these estimates was obtained from records furnished by FieldPoint Petroleum Corporation and from commercially available data sources. For purposes of this report, the individual well test and production data, as reported by the above sources, were accepted as represented together with all other factual data presented by FieldPoint Petroleum Corporation including the extent and character of the interest evaluated. No field inspection of the properties was performed.

All reserve estimates herein have been performed in accordance with sound engineering principles and generally accepted industry practice. As in all aspects of oil and gas evaluations, there are uncertainties inherent in the interpretation of engineering and geologic data and all conclusions and projections contained herein represent the informed, professional judgment of the undersigned. The reserves may or may not be recovered, and the revenues therefrom and the cost related thereto could be more or less than the estimated amounts. Estimates of reserves may increase or decrease as a result of future operations, governmental policies, product supply and demand, and also are subject to revision as additional operating history becomes available and as economic conditions change.

FIELDPOINT PETROLEUM CORPORATION March 2, 2012

The evaluation of potential environmental liability costs from the operation and abandonment of the properties evaluated was beyond the scope of this report. In addition, no evaluation was made to determine the degree of operator compliance with current environmental rules, regulations and reporting requirements. Therefore, no estimate of the potential economic liability, if any, from environmental concerns is included in the projections presented herein.

FieldPoint Petroleum Corporation provided basic well information, operating costs, initial test rates and ownership interests which we have accepted as correct. Historical production data was obtained from public sources such as state regulatory agencies, Lasser Production Data Services, Drillinginfo and IHS Energy Data Services. Digital, hard copy and other pertinent data relating to the properties evaluated will be retained in our files and will be available for review upon request. We have not inspected or performed well tests on the individual properties in this report.

We do not own an interest in the subject properties. The employment to make this study and the compensation is not contingent on our estimates of reserves and future income for the subject properties.

We appreciate the opportunity to prepare this report. If you have any questions regarding this report or if we can assist in any other way please do not hesitate to call. Thank you again for the opportunity to be of service in this matter.

Sincerely,

Wayman T. Gore, Jr., P.E.
President
PGH Petroleum & Environmental Engineers, L.L.C.

David N. Dennard, P.E.
Staff Engineer
PGH Petroleum & Environmental Engineers, L.L.C.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines, " Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Summaries by Reserve Category

Date : 03/02/2012 9:44:28AM

ECONOMIC SUMMARY PROJECTION

Proved Rsv Class

Project Name : FieldPoint Petroleum Corporation
Partner : All Cases
Case Type : REPORT BREAK TOTAL CASE

As Of Date : 01/01/2012
Discount Rate (%) : 10.00
All Cases

Cum Oil (Mbbl) : **76,133.90**
Cum Gas (MMcf) : **27,280.63**
Cum NGL (Mgal) : **17.12**

Year	Gross Oil (Mbbl)	Gross Gas (MMcf)	Gross NGL (Mgal)	Net Oil (Mbbl)	Net Gas (MMcf)	Net NGL (Mgal)	Oil Price ($/bbl)	Gas Price ($/Mcf)	NGL Price ($/gal)	Total Revenue (M$)
2012	344.29	1,168.12	196.09	114.01	197.51	84.81	91.04	4.21	0.92	11,289.45
2013	323.98	823.12	184.85	89.90	145.66	79.95	90.95	4.72	0.92	8,937.27
2014	327.84	741.04	174.75	87.79	138.69	75.58	91.11	4.67	0.92	8,715.27
2015	267.37	591.98	165.20	72.70	112.96	71.45	91.05	4.63	0.92	7,207.60
2016	232.78	507.13	156.58	63.36	96.87	67.72	91.00	4.59	0.92	6,272.18
2017	202.76	433.35	147.61	55.90	84.01	63.84	90.95	4.59	0.92	5,527.94
2018	179.05	380.09	139.54	48.84	74.38	60.35	90.89	4.59	0.92	4,835.88
2019	161.29	337.95	131.91	44.40	66.81	57.05	90.85	4.59	0.92	4,392.57
2020	147.03	305.22	125.03	40.70	60.72	54.08	90.82	4.59	0.92	4,024.92
2021	133.82	275.45	117.87	37.15	54.86	50.98	90.80	4.58	0.92	3,670.80
2022	107.10	247.96	111.42	31.60	49.23	48.19	90.54	4.56	0.92	3,129.35
2023	96.57	224.45	105.33	28.92	44.92	45.56	90.47	4.56	0.92	2,862.83
2024	89.03	191.26	99.84	26.81	40.15	43.18	90.44	4.60	0.92	2,648.63
2025	81.46	168.08	94.12	24.46	36.35	40.71	90.41	4.62	0.92	2,416.95
2026	75.28	154.10	88.97	22.74	33.46	38.48	90.39	4.61	0.92	2,245.45
Rem	654.77	1,487.97	1,313.35	216.78	333.74	568.02	90.08	3.89	0.92	21,348.57
Total	**3,424.42**	**8,037.26**	**3,352.46**	**1,006.07**	**1,570.31**	**1,449.94**	**90.71**	**4.42**	**0.92**	**99,525.66**
Ult	**79,558.32**	**35,317.89**	**3,369.58**							

Year	Well Count	Net Tax Production (M$)	Net Tax AdValorem (M$)	Net Investment (M$)	Net Lease Costs (M$)	Net Well Costs (M$)	Other Costs (M$)	Net Profits (M$)	Annual Cash Flow (M$)	Cum Disc. Cash Flow (M$)
2012	48.00	767.58	429.91	2,538.75	1,393.33	0.00	0.00	0.00	6,159.89	5,851.82
2013	50.00	600.90	301.41	2,234.84	1,375.37	0.00	0.00	0.00	4,424.74	9,689.28
2014	50.00	584.37	263.10	0.00	1,418.66	0.00	0.00	0.00	6,449.14	14,729.19
2015	51.00	478.80	211.55	150.00	1,392.93	0.00	0.00	0.00	4,974.32	18,245.85
2016	50.00	413.28	180.62	0.00	1,370.93	0.00	0.00	0.00	4,307.35	21,001.91
2017	49.00	362.94	157.18	0.00	1,360.92	0.00	0.00	0.00	3,646.89	23,113.61
2018	48.00	319.14	136.64	0.00	1,224.09	0.00	0.00	0.00	3,156.01	24,767.74
2019	45.00	289.19	123.14	0.00	1,219.34	0.00	0.00	0.00	2,760.90	26,077.62
2020	45.00	264.44	111.98	0.00	1,214.43	0.00	0.00	0.00	2,434.07	27,122.93
2021	42.00	240.94	101.40	0.00	1,196.51	0.00	0.00	0.00	2,131.95	27,951.60
2022	39.00	203.99	86.42	0.00	954.26	0.00	0.00	0.00	1,884.68	28,614.72
2023	36.00	186.12	78.53	0.00	920.73	0.00	0.00	0.00	1,677.45	29,149.00
2024	34.00	171.79	72.14	0.00	905.13	0.00	0.00	0.00	1,499.56	29,581.35
2025	31.00	157.11	65.45	0.00	863.81	0.00	0.00	0.00	1,330.58	29,928.55
2026	29.00	145.89	60.41	0.00	852.96	0.00	0.00	0.00	1,186.19	30,208.76
Rem.		1,394.62	552.31	0.00	10,106.65	0.00	0.00	0.00	9,294.99	1,118.29
Total		**6,581.12**	**2,932.18**	**4,923.59**	**27,770.07**	**0.00**	**0.00**	**0.00**	**57,318.70**	**31,327.05**

Disc. Initial Invest. (M$) :	2,412.632
ROInvestment (disc/undisc) :	13.98 /23.83
Years to Payout :	0.26
Internal ROR (%) :	>1000

Present Worth Profile (M$)

PW	5.00% :	40,507.86
PW	9.00% :	32,816.73
PW	10.00% :	31,327.05
PW	12.00% :	28,715.23
PW	15.00% :	25,512.76
PW	20.00% :	21,491.14

Date : 03/02/2012 9:44:28AM

ECONOMIC SUMMARY PROJECTION

Proved Rsv Class
Producing Rsv Category

Project Name : FieldPoint Petroleum Corporation
Partner : All Cases
Case Type : REPORT BREAK TOTAL CASE

As Of Date : 01/01/2012
Discount Rate (%) : 10.00
All Cases

Cum Oil (Mbbl) : **76,133.90**
Cum Gas (MMcf) : **27,280.63**
Cum NGL (Mgal) : **17.12**

Year	Gross Oil (Mbbl)	Gross Gas (MMcf)	Gross NGL (Mgal)	Net Oil (Mbbl)	Net Gas (MMcf)	Net NGL (Mgal)	Oil Price ($/bbl)	Gas Price ($/Mcf)	NGL Price ($/gal)	Total Revenue (M$)
2012	301.40	525.71	196.09	98.58	128.91	84.81	91.01	4.45	0.92	9,622.29
2013	207.48	351.24	184.85	66.16	87.02	79.95	90.93	4.52	0.92	6,481.93
2014	175.02	303.92	174.75	55.54	73.61	75.58	90.89	4.53	0.92	5,450.81
2015	154.80	272.80	165.20	48.97	65.62	71.45	90.85	4.54	0.92	4,812.68
2016	140.32	247.97	156.58	44.42	59.20	67.72	90.83	4.52	0.92	4,364.14
2017	128.07	226.88	147.61	40.67	54.16	63.84	90.80	4.52	0.92	3,995.79
2018	116.32	208.81	139.54	36.17	49.83	60.35	90.74	4.52	0.92	3,562.27
2019	107.32	192.18	131.91	33.62	46.15	57.05	90.72	4.52	0.92	3,311.08
2020	99.74	178.64	125.03	31.40	43.02	54.08	90.70	4.52	0.92	3,091.58
2021	92.12	164.88	117.87	29.07	39.62	50.98	90.69	4.51	0.92	2,861.19
2022	69.97	150.59	111.42	24.51	35.99	48.19	90.36	4.47	0.92	2,419.87
2023	63.37	138.41	105.33	22.67	33.36	45.56	90.30	4.46	0.92	2,237.83
2024	59.15	127.30	99.84	21.26	30.92	43.18	90.28	4.49	0.92	2,097.40
2025	54.63	118.18	94.12	19.54	28.76	40.71	90.25	4.49	0.92	1,930.40
2026	51.06	108.89	88.97	18.35	26.72	38.48	90.24	4.49	0.92	1,811.42
Rem	443.78	1,077.43	1,313.35	186.63	284.52	568.02	89.92	3.70	0.92	18,355.81
Total	**2,264.56**	**4,393.82**	**3,352.46**	**777.56**	**1,087.42**	**1,449.94**	**90.55**	**4.29**	**0.92**	**76,406.48**
Ult	**78,398.46**	**31,674.45**	**3,369.58**							

Year	Well Count	Net Tax Production (M$)	Net Tax AdValorem (M$)	Net Investment (M$)	Net Lease Costs (M$)	Net Well Costs (M$)	Other Costs (M$)	Net Profits (M$)	Annual Cash Flow (M$)	Cum Disc. Cash Flow (M$)
2012	46.00	646.53	350.27	0.00	1,377.84	0.00	0.00	0.00	7,247.66	6,940.18
2013	43.00	425.22	204.15	0.00	1,312.58	0.00	0.00	0.00	4,539.98	10,859.57
2014	41.00	354.12	161.32	0.00	1,308.09	0.00	0.00	0.00	3,627.28	13,692.09
2015	41.00	310.83	137.74	0.00	1,280.44	0.00	0.00	0.00	3,083.68	15,871.32
2016	40.00	280.80	122.30	0.00	1,254.66	0.00	0.00	0.00	2,706.38	17,602.30
2017	39.00	256.76	110.36	0.00	1,244.65	0.00	0.00	0.00	2,384.01	18,982.31
2018	38.00	231.12	97.69	0.00	1,107.82	0.00	0.00	0.00	2,125.64	20,096.13
2019	35.00	214.66	90.07	0.00	1,103.07	0.00	0.00	0.00	1,903.28	20,998.95
2020	35.00	200.31	83.50	0.00	1,098.16	0.00	0.00	0.00	1,709.60	21,733.03
2021	32.00	185.48	76.80	0.00	1,080.24	0.00	0.00	0.00	1,518.67	22,323.24
2022	29.00	155.53	64.97	0.00	837.99	0.00	0.00	0.00	1,361.37	22,802.16
2023	26.00	143.55	59.75	0.00	804.46	0.00	0.00	0.00	1,230.06	23,193.89
2024	24.00	134.40	55.68	0.00	791.93	0.00	0.00	0.00	1,115.38	23,515.43
2025	22.00	124.23	51.01	0.00	752.54	0.00	0.00	0.00	1,002.62	23,777.03
2026	20.00	116.63	47.62	0.00	741.69	0.00	0.00	0.00	905.47	23,990.90
Rem.		1,201.39	470.20	0.00	8,706.51	0.00	0.00	0.00	7,977.71	911.89
Total		**4,981.57**	**2,183.41**	**0.00**	**24,802.69**	**0.00**	**0.00**	**0.00**	**44,438.81**	**24,902.78**

Disc. Initial Invest. (M$) :	0.000
ROInvestment (disc/undisc) :	0.00 /0.00
Years to Payout :	0.00
Internal ROR (%) :	0.00

Present Worth Profile (M$)

PW	5.00% :	31,588.92
PW	9.00% :	25,973.13
PW	10.00% :	24,902.78
PW	12.00% :	23,038.08
PW	15.00% :	20,769.62
PW	20.00% :	17,940.91

Date : 03/02/2012 10:11:36AM

ECONOMIC SUMMARY PROJECTION

Proved Rsv Class
Behind Pipe Rsv Category

Project Name : FieldPoint Petroleum Corporation
Partner : All Cases
Case Type : REPORT BREAK TOTAL CASE

As Of Date : 01/01/2012
Discount Rate (%) : 10.00
All Cases

Cum Oil (Mbbl) : **0.00**
Cum Gas (MMcf) : **0.00**
Cum NGL (Mgal) : **0.00**

Year	Gross Oil (Mbbl)	Gross Gas (MMcf)	Gross NGL (Mgal)	Net Oil (Mbbl)	Net Gas (MMcf)	Net NGL (Mgal)	Oil Price ($/bbl)	Gas Price ($/Mcf)	NGL Price ($/gal)	Total Revenue (M$)
2012	0.00	568.77	0.00	0.00	42.09	0.00	0.00	3.53	0.00	148.69
2013	37.87	342.69	0.00	4.17	27.19	0.00	90.83	5.03	0.00	515.12
2014	27.30	218.75	0.00	3.00	17.51	0.00	90.83	5.21	0.00	363.94
2015	19.19	152.04	0.00	2.11	12.18	0.00	90.83	5.23	0.00	255.36
2016	14.90	113.82	0.00	1.64	9.14	0.00	90.83	5.28	0.00	197.19
2017	12.16	88.90	0.00	1.34	7.17	0.00	90.83	5.35	0.00	159.83
2018	10.30	72.09	0.00	1.13	5.83	0.00	90.83	5.43	0.00	134.62
2019	8.95	60.00	0.00	0.98	4.87	0.00	90.83	5.51	0.00	116.26
2020	7.94	51.08	0.00	0.87	4.16	0.00	90.83	5.58	0.00	102.57
2021	7.10	43.77	0.00	0.78	3.58	0.00	90.83	5.66	0.00	91.19
2022	6.39	37.68	0.00	0.70	3.10	0.00	90.83	5.75	0.00	81.63
2023	5.75	32.46	0.00	0.63	2.68	0.00	90.83	5.84	0.00	73.09
2024	5.19	15.56	0.00	0.57	1.40	0.00	90.83	7.51	0.00	62.37
2025	4.66	6.25	0.00	0.51	0.69	0.00	90.83	10.81	0.00	53.96
2026	4.19	5.62	0.00	0.46	0.62	0.00	90.83	10.81	0.00	48.56
Rem	31.22	41.89	0.00	3.43	4.61	0.00	90.83	10.81	0.00	361.71
Total	**203.11**	**1,851.38**	**0.00**	**22.34**	**146.81**	**0.00**	**90.83**	**5.02**	**0.00**	**2,766.06**
Ult	**203.11**	**1,851.38**	**0.00**							

Year	Well Coun	Net Tax Production (M$)	Net Tax AdValorem (M$)	Net Investment (M$)	Net Lease Costs (M$)	Net Well Costs (M$)	Other Costs (M$)	Net Profits (M$)	Annual Cash Flow (M$)	Cum Disc. Cash Flow (M$)
2012	1.00	12.18	3.72	45.00	4.99	0.00	0.00	0.00	82.80	77.45
2013	2.00	38.03	12.88	17.04	11.00	0.00	0.00	0.00	436.18	451.59
2014	2.00	26.81	9.10	0.00	12.20	0.00	0.00	0.00	315.83	698.75
2015	2.00	18.81	6.38	0.00	12.20	0.00	0.00	0.00	217.97	853.02
2016	2.00	14.51	4.93	0.00	12.20	0.00	0.00	0.00	165.55	959.01
2017	2.00	11.75	4.00	0.00	12.20	0.00	0.00	0.00	131.88	1,035.40
2018	2.00	9.89	3.37	0.00	12.20	0.00	0.00	0.00	109.16	1,092.64
2019	2.00	8.54	2.91	0.00	12.20	0.00	0.00	0.00	92.62	1,136.59
2020	2.00	7.53	2.56	0.00	12.20	0.00	0.00	0.00	80.27	1,171.07
2021	2.00	6.69	2.28	0.00	12.20	0.00	0.00	0.00	70.02	1,198.29
2022	2.00	5.98	2.04	0.00	12.20	0.00	0.00	0.00	61.40	1,219.90
2023	2.00	5.35	1.83	0.00	12.20	0.00	0.00	0.00	53.71	1,237.01
2024	2.00	4.54	1.56	0.00	9.12	0.00	0.00	0.00	47.15	1,250.60
2025	1.00	3.91	1.35	0.00	7.20	0.00	0.00	0.00	41.50	1,261.43
2026	1.00	3.52	1.21	0.00	7.20	0.00	0.00	0.00	36.63	1,270.09
Rem.		26.19	9.04	0.00	119.83	0.00	0.00	0.00	206.65	30.92
Total		**204.22**	**69.15**	**62.04**	**281.33**	**0.00**	**0.00**	**0.00**	**2,149.32**	**1,301.01**

Disc. Initial Invest. (M$) :	15.176
ROInvestment (disc/undisc) :	86.73 /127.13
Years to Payout :	0.39
Internal ROR (%) :	417.77

Present Worth Profile (M$)

PW	5.00% :	1,627.69
PW	9.00% :	1,356.14
PW	10.00% :	1,301.01
PW	12.00% :	1,202.28
PW	15.00% :	1,077.46
PW	20.00% :	914.20

Date : 03/02/2012 10:11:36AM

ECONOMIC SUMMARY PROJECTION

Proved Rsv Class
Undeveloped Rsv Category

Project Name : FieldPoint Petroleum Corporation
Partner : All Cases
Case Type : REPORT BREAK TOTAL CASE

As Of Date : 01/01/2012
Discount Rate (%) : 10.00
All Cases

Cum Oil (Mbbl) : **0.00**
Cum Gas (MMcf) : **0.00**
Cum NGL (Mgal) : **0.00**

Year	Gross Oil (Mbbl)	Gross Gas (MMcf)	Gross NGL (Mgal)	Net Oil (Mbbl)	Net Gas (MMcf)	Net NGL (Mgal)	Oil Price ($/bbl)	Gas Price ($/Mcf)	NGL Price ($/gal)	Total Revenue (M$)
2012	42.88	73.65	0.00	15.44	26.51	0.00	91.21	4.17	0.00	1,518.48
2013	78.63	129.19	0.00	19.58	31.45	0.00	91.05	5.01	0.00	1,940.21
2014	125.51	218.37	0.00	29.25	47.57	0.00	91.57	4.68	0.00	2,900.52
2015	93.38	167.15	0.00	21.61	35.16	0.00	91.52	4.60	0.00	2,139.56
2016	77.56	145.34	0.00	17.30	28.53	0.00	91.46	4.51	0.00	1,710.86
2017	62.53	117.56	0.00	13.89	22.68	0.00	91.41	4.51	0.00	1,372.32
2018	52.43	99.18	0.00	11.54	18.71	0.00	91.35	4.51	0.00	1,139.00
2019	45.02	85.77	0.00	9.79	15.79	0.00	91.30	4.51	0.00	965.23
2020	39.35	75.49	0.00	8.43	13.53	0.00	91.26	4.51	0.00	830.78
2021	34.60	66.80	0.00	7.30	11.65	0.00	91.21	4.52	0.00	718.42
2022	30.74	59.69	0.00	6.38	10.14	0.00	91.17	4.53	0.00	627.85
2023	27.46	53.58	0.00	5.61	8.88	0.00	91.13	4.53	0.00	551.90
2024	24.69	48.41	0.00	4.98	7.83	0.00	91.10	4.53	0.00	488.86
2025	22.17	43.65	0.00	4.41	6.90	0.00	91.07	4.53	0.00	432.60
2026	20.03	39.58	0.00	3.93	6.12	0.00	91.04	4.52	0.00	385.46
Rem	179.78	368.64	0.00	26.71	44.62	0.00	91.15	4.39	0.00	2,631.05
Total	**956.76**	**1,792.05**	**0.00**	**206.17**	**336.08**	**0.00**	**91.31**	**4.55**	**0.00**	**20,353.11**
Ult	**956.76**	**1,792.05**	**0.00**							

Year	Well Count	Net Tax Production (M$)	Net Tax AdValorem (M$)	Net Investment (M$)	Net Lease Costs (M$)	Net Well Costs (M$)	Other Costs (M$)	Net Profits (M$)	Annual Cash Flow (M$)	Cum Disc. Cash Flow (M$)
2012	1.00	108.88	75.92	2,493.75	10.50	0.00	0.00	0.00	-1,170.57	-1,165.82
2013	5.00	137.65	84.38	2,217.80	51.79	0.00	0.00	0.00	-551.42	-1,621.88
2014	7.00	203.45	92.68	0.00	98.37	0.00	0.00	0.00	2,506.02	338.35
2015	8.00	149.17	67.43	150.00	100.29	0.00	0.00	0.00	1,672.68	1,521.52
2016	8.00	117.97	53.40	0.00	104.07	0.00	0.00	0.00	1,435.42	2,440.61
2017	8.00	94.42	42.83	0.00	104.07	0.00	0.00	0.00	1,131.00	3,095.89
2018	8.00	78.14	35.58	0.00	104.07	0.00	0.00	0.00	921.21	3,578.97
2019	8.00	65.99	30.17	0.00	104.07	0.00	0.00	0.00	765.00	3,942.08
2020	8.00	56.60	25.91	0.00	104.07	0.00	0.00	0.00	644.19	4,218.84
2021	8.00	48.77	22.32	0.00	104.07	0.00	0.00	0.00	543.26	4,430.07
2022	8.00	42.48	19.40	0.00	104.07	0.00	0.00	0.00	461.90	4,592.66
2023	8.00	37.21	16.95	0.00	104.07	0.00	0.00	0.00	393.67	4,718.10
2024	8.00	32.85	14.91	0.00	104.07	0.00	0.00	0.00	337.04	4,815.31
2025	8.00	28.97	13.09	0.00	104.07	0.00	0.00	0.00	286.46	4,890.09
2026	8.00	25.74	11.57	0.00	104.07	0.00	0.00	0.00	244.08	4,947.78
Rem.		167.04	73.07	0.00	1,280.31	0.00	0.00	0.00	1,110.63	175.48
Total		**1,395.33**	**679.62**	**4,861.55**	**2,686.05**	**0.00**	**0.00**	**0.00**	**10,730.57**	**5,123.25**

Disc. Initial Invest. (M$) :	2,397.457
ROInvestment (disc/undisc) :	3.14 /5.30
Years to Payout :	2.65
Internal ROR (%) :	51.22

Present Worth Profile (M$)

PW	5.00% :	7,291.25
PW	9.00% :	5,487.46
PW	10.00% :	5,123.25
PW	12.00% :	4,474.87
PW	15.00% :	3,665.68
PW	20.00% :	2,636.03

– One-Line Summary –

Sort by
Reserve Category & Lease Name

All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Economic Information

Date : 3/2/2012
Time : 9:47:35AM
File : oint Reserves 2012-01.Phd

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
Proved Rsv Class	**Total**	**3,424.42**	**8,037.26**	**1,006.07**	**1,570.31**	**99,525.66**	**9,513.30**	**27,770.07**	**4,923.59**	**57,318.70**	**31,327.05**
Proved Rsv Class											
Producing Rsv Category	**Total**	**2,264.56**	**4,393.82**	**777.56**	**1,087.42**	**76,406.48**	**7,164.98**	**24,802.69**	**0.00**	**44,438.81**	**24,902.78**
APACHE BROMIDE SAND UNIT	PDP	755.83	354.29	145.951	68.41	13,729.85	1,317.38	6,527.65	0.00	5,884.82	3,342.66
ARROWHEAD #1-49	PDP	21.48	0.00	12.860	0.00	1,175.01	83.43	476.03	0.00	615.56	438.35
BUCHANAN -L- Lease	PDP	37.39	200.05	3.799	20.32	414.38	31.37	179.65	0.00	203.36	112.86
BUCHANAN M 1	PDP	13.70	72.60	1.392	7.38	150.93	11.43	59.57	0.00	79.93	55.44
BUCHANAN P 1	PDP	8.30	24.91	0.844	2.53	86.78	6.40	28.29	0.00	52.09	43.41
CARLESTON 1	PDP	2.17	0.00	1.235	0.00	109.64	7.78	65.77	0.00	36.08	28.13
CARLESTON, HERBERT 3	PDP	2.93	9.52	1.788	5.81	193.49	14.75	92.47	0.00	86.27	66.54
CHMELAR, EUGENE -A- 1 L	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CLEMMONS SUNBURST FEDERAL 001	PDP	17.75	41.71	5.226	12.28	513.00	49.53	177.70	0.00	285.77	209.06
CRONOS FEE 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
East Lusk 1 Fed #1H	PDP	315.59	378.71	113.612	136.33	10,930.04	1,327.69	687.11	0.00	8,915.24	7,039.42
ELKHORN 14	PDP	5.00	0.00	4.374	0.00	386.33	33.07	126.55	0.00	226.71	142.82
ELKHORN A ST 015658A 15	PDP	16.60	0.00	13.696	0.00	1,209.62	103.54	411.30	0.00	694.78	299.61
FIELDS 4-1	PDP	0.00	119.44	0.000	4.48	13.09	1.26	4.21	0.00	7.63	3.65
FISCHER #02	PDP	7.28	13.94	1.074	2.06	107.64	8.00	14.65	0.00	84.99	63.21
HERMES FEE 001	PDP	0.00	75.74	0.000	8.33	28.07	3.00	9.37	0.00	15.71	11.72
HERN 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HOSS 7800 RA SUA;CUSHMAN 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HOSS RA SUH;CUSHMAN 002	PDP	6.47	1,078.67	0.593	98.91	468.43	39.42	134.50	0.00	294.50	167.00
JENNINGS FEDERAL 001	PDP	142.57	47.80	103.365	34.65	9,571.82	919.53	1,863.75	0.00	6,788.55	2,729.46
KASPER 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KINNEY ST #38	PDP	99.15	0.00	86.755	0.00	7,608.18	651.26	1,500.00	0.00	5,456.92	1,821.78
KINNEY ST #38	PDP	9.59	0.00	8.387	0.00	735.53	62.96	160.97	0.00	511.60	291.68
KORCZAK FED. #01	PDP	131.70	176.74	14.487	19.44	1,525.93	148.65	204.14	0.00	1,173.14	707.43
LORENZ 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MARQUIS #7 7	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MCCLINTIC -A- 1	PDP	105.50	126.60	6.003	7.20	581.27	41.93	184.75	0.00	354.59	130.90
MENZEL 1	PDP	7.87	0.00	4.582	0.00	406.67	28.87	158.74	0.00	219.06	126.37
MERCURY FEE 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MERSIOVSKY 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MERSLOVSKY #01	PDP	1.96	0.00	1.282	0.00	113.81	8.08	66.42	0.00	39.30	25.01

All Estimates Herein are Part of the PGH Petroleum & Environmental Engineers, L.L.C. Report and are Subject to its Conditions.

All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Date : 3/2/2012
Time : 9:47:35AM
File : oint Reserves 2012-01.Phd

Economic Information

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
MILROSE-LORENZ 4	PDP	1.85	5.10	0.348	0.96	36.58	2.76	9.73	0.00	24.09	17.17
MILROSE-MARQUIS A 3	PDP	2.39	7.40	0.373	1.16	40.02	3.04	13.41	0.00	23.57	16.33
MILROSE-MARQUIS B 4	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MILROSE-VAHRENKAMP 1	PDP	1.11	2.83	0.162	0.41	16.88	1.27	7.62	0.00	7.99	6.21
MOERBE 5	PDP	2.69	0.00	1.147	0.00	101.83	7.23	51.74	0.00	42.86	30.39
MOERBE, VICTOR 3	PDP	0.13	1.19	0.097	0.87	13.86	1.14	11.81	0.00	0.92	0.88
NITSCHE, R.J. 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN WEISE 1	PDP	0.13	0.39	0.074	0.22	7.84	0.60	6.08	0.00	1.17	1.12
NORTH BILBREY 7 FEDERAL 001	PDP	0.00	1,352.89	0.000	490.33	2,681.69	302.74	442.34	0.00	1,936.60	826.22
NORTH BLOCK 12 UNIT	PDP	112.62	0.00	94.216	0.00	8,448.87	599.87	4,058.13	0.00	3,790.87	2,133.27
PETERS #5	PDP	1.45	6.94	0.828	3.97	97.28	7.60	66.36	0.00	23.32	17.50
PETERS ‘C’ 9	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETERS 8	PDP	2.04	5.66	1.534	4.24	161.51	12.20	66.07	0.00	83.23	65.69
QUINOCO SULIMAR 001	PDP	60.20	0.00	51.473	0.00	4,591.23	440.30	1,343.76	0.00	2,807.18	1,366.15
RUSH SPRINGS MEDRANO UNIT	PDP	310.20	26.27	50.221	4.25	4,738.36	454.65	2,549.97	0.00	1,733.74	1,306.34
S & M ENERGY-LORENZ 3	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S & M ENERGY-MARQUIS 6	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S & M ENERGY-MOERBE 2	PDP	0.74	3.40	0.409	1.88	47.54	3.70	25.16	0.00	18.67	15.68
S & M ENERGY-PETERS B 7	PDP	6.63	11.11	3.535	5.92	349.19	25.82	172.52	0.00	150.85	88.27
S&M ENERGY-DEAN STUESSY - E- 7	PDP	0.00	7.64	0.000	4.07	24.41	2.44	16.70	0.00	5.26	4.57
S&M ENERGY-DEAN STUESSY A 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY B 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY C 4	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY D 5	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-HERBERT STUESSY -A- 6	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-HERBERT STUESSY 3	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-PETERS A	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-SPRETZ 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-SPRETZ A 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCOTT PETROLEUM-PETERS A 6	PDP	0.08	0.46	0.058	0.35	7.22	0.57	6.32	0.00	0.33	0.32
SHADE 0	PDP	29.89	164.40	22.972	124.70	3,178.59	259.88	1,627.32	0.00	1,291.39	758.61
SHEARN FEDERAL 003	PDP	4.88	0.00	4.028	0.00	365.51	35.05	172.36	0.00	158.10	143.04
STATE OF TEXAS -Z- 0	PDP	13.82	0.00	12.096	0.00	1,109.09	78.75	830.59	0.00	199.75	166.70
STAUSS 1	PDP	0.00	51.28	0.000	1.77	6.57	0.66	5.45	0.00	0.46	0.46
STEINBACH 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STEINBACH ET AL 1	PDP	2.16	12.35	0.994	5.68	122.30	9.67	55.78	0.00	56.85	39.60

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All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Date : 3/2/2012
Time : 9:47:35AM
File : oint Reserves 2012-01.Phd

Economic Information

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
SUNBURST SPENCE FEDERAL 002	PDP	0.02	0.15	0.006	0.04	0.67	0.06	0.59	0.00	0.01	0.01
URBAN #2 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
URBAN #3 3	PDP	2.11	10.31	1.455	7.10	171.66	13.42	112.04	0.00	46.20	34.46
URBAN 1	PDP	0.58	3.36	0.230	1.32	28.28	2.24	17.23	0.00	8.81	7.34
WACHSMANN 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Proved Rsv Class											
Behind Pipe Rsv Category	**Total**	**203.11**	**1,851.38**	**22.34**	**146.81**	**2,766.06**	**273.37**	**281.33**	**62.04**	**2,149.32**	**1,301.01**
KORCZAK FED. #01	PBP	203.11	272.57	22.342	29.98	2,353.34	229.25	219.42	17.04	1,887.63	1,093.00
MERCURY FEE #01	PBP	0.00	1,578.81	0.000	116.83	412.73	44.12	61.91	45.00	261.70	208.01
Proved Rsv Class											
Undeveloped Rsv Category	**Total**	**956.76**	**1,792.05**	**206.17**	**336.08**	**20,353.11**	**2,074.95**	**2,686.05**	**4,861.55**	**10,730.57**	**5,123.25**
BUCHANAN -L- PUD #01	PUD	75.05	222.89	7.625	22.65	771.79	56.96	276.93	150.00	287.90	117.79
BUCHANAN -M- PUD #01	PUD	69.01	204.96	7.012	20.82	706.09	52.14	160.85	150.00	343.10	110.58
BUCHANAN -M- PUD #02	PUD	69.01	204.96	7.012	20.82	706.09	52.14	160.86	150.00	343.09	93.72
East Lusk 1 Fed #2H	PUD	192.93	331.33	69.455	119.28	6,831.59	831.41	445.57	2,493.75	3,060.86	1,631.89
FLYING M SOUTH (ABO) PUD #01	PUD	215.94	360.61	63.572	106.16	6,303.81	609.35	432.35	1,099.00	4,163.11	2,131.42
KORCZAK FED. PUD #1	PUD	203.41	272.98	22.375	30.03	2,356.90	229.60	211.30	340.80	1,575.20	782.72
MCCLINTIC -A- PUD #01	PUD	104.30	187.73	5.934	10.68	585.90	42.58	143.01	78.00	322.31	77.47
QUINOCO SULIMAR PUD #01	PUD	27.11	6.59	23.182	5.63	2,090.94	200.78	855.18	400.00	634.99	177.66

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– One-Line Summary –

Sort by
Field

All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Economic Information

Date : 3/2/2012
Time : 9:49:01AM
File : oint Reserves 2012-01.Phd

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
Grand Total	**Total**	**3,424.42**	**8,037.26**	**1,006.07**	**1,570.31**	**99,525.66**	**9,513.30**	**27,770.07**	**4,923.59**	**57,318.70**	**31,327.05**
APACHE Field											
APACHE BROMIDE SAND UNIT	PDP	755.83	354.29	145.951	68.41	13,729.85	1,317.38	6,527.65	0.00	5,884.82	3,342.66
BIG MUDDY Field	**Total**	**21.60**	**0.00**	**18.07**	**0.00**	**1,595.95**	**136.61**	**537.85**	**0.00**	**921.49**	**442.42**
ELKHORN 14	PDP	5.00	0.00	4.374	0.00	386.33	33.07	126.55	0.00	226.71	142.82
ELKHORN A ST 015658A 15	PDP	16.60	0.00	13.696	0.00	1,209.62	103.54	411.30	0.00	694.78	299.61
BIG MUDDY (DAKOTA) Field											
KINNEY ST #38	PDP	99.15	0.00	86.755	0.00	7,608.18	651.26	1,500.00	0.00	5,456.92	1,821.78
BIG MUDDY (WALL CREEK) Field											
KINNEY ST #38	PDP	9.59	0.00	8.387	0.00	735.53	62.96	160.97	0.00	511.60	291.68
BILBREY Field											
NORTH BILBREY 7 FEDERAL 001	PDP	0.00	1,352.89	0.000	490.33	2,681.69	302.74	442.34	0.00	1,936.60	826.22
BLOCK 6 Field											
STATE OF TEXAS -Z- 0	PDP	13.82	0.00	12.096	0.00	1,109.09	78.75	830.59	0.00	199.75	166.70
BLOCK A-49 Field	**Total**	**134.10**	**0.00**	**107.08**	**0.00**	**9,623.88**	**683.30**	**4,534.16**	**0.00**	**4,406.43**	**2,571.61**
ARROWHEAD #1-49	PDP	21.48	0.00	12.860	0.00	1,175.01	83.43	476.03	0.00	615.56	438.35
NORTH BLOCK 12 UNIT	PDP	112.62	0.00	94.216	0.00	8,448.87	599.87	4,058.13	0.00	3,790.87	2,133.27
CHICKASHA Field											
RUSH SPRINGS MEDRANO UNIT	PDP	310.20	26.27	50.221	4.25	4,738.36	454.65	2,549.97	0.00	1,733.74	1,306.34
FLYING M Field	**Total**	**17.77**	**41.86**	**5.23**	**12.32**	**513.67**	**49.60**	**178.29**	**0.00**	**285.78**	**209.07**
CLEMMONS SUNBURST FEDERAL 001	PDP	17.75	41.71	5.226	12.28	513.00	49.53	177.70	0.00	285.77	209.06
SUNBURST SPENCE FEDERAL 002	PDP	0.02	0.15	0.006	0.04	0.67	0.06	0.59	0.00	0.01	0.01
FLYING M SOUTH (ABO) Field											
FLYING M SOUTH (ABO) PUD #01	PUD	215.94	360.61	63.572	106.16	6,303.81	609.35	432.35	1,099.00	4,163.11	2,131.42
GIDDINGS Field	**Total**	**29.89**	**164.40**	**22.97**	**124.70**	**3,178.59**	**259.88**	**1,627.32**	**0.00**	**1,291.39**	**758.61**
CHMELAR, EUGENE -A- 1 L	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SHADE 0	PDP	29.89	164.40	22.972	124.70	3,178.59	259.88	1,627.32	0.00	1,291.39	758.61
LONGWOOD Field	**Total**	**6.47**	**1,078.67**	**0.59**	**98.91**	**468.43**	**39.42**	**134.50**	**0.00**	**294.50**	**167.00**
HOSS 7800 RA SUA;CUSHMAN 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HOSS RA SUH;CUSHMAN 002	PDP	6.47	1,078.67	0.593	98.91	468.43	39.42	134.50	0.00	294.50	167.00
LOVING Field	**Total**	**0.00**	**1,654.55**	**0.00**	**125.16**	**440.80**	**47.12**	**71.28**	**45.00**	**277.40**	**219.73**

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All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Date : 3/2/2012
Time : 9:49:01AM
File : oint Reserves 2012-01.Phd

Economic Information

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
CRONOS FEE 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HERMES FEE 001	PDP	0.00	75.74	0.000	8.33	28.07	3.00	9.37	0.00	15.71	11.72
MERCURY FEE 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MERCURY FEE #01	PBP	0.00	1,578.81	0.000	116.83	412.73	44.12	61.91	45.00	261.70	208.01
LUSK Field	**Total**	**1,194.19**	**1,480.12**	**349.66**	**369.72**	**33,935.12**	**3,721.17**	**3,803.65**	**2,851.59**	**23,558.72**	**14,126.95**
East Lusk 1 Fed #1H	PDP	315.59	378.71	113.612	136.33	10,930.04	1,327.69	687.11	0.00	8,915.24	7,039.42
JENNINGS FEDERAL 001	PDP	142.57	47.80	103.365	34.65	9,571.82	919.53	1,863.75	0.00	6,788.55	2,729.46
KORCZAK FED. #01	PDP	131.70	176.74	14.487	19.44	1,525.93	148.65	204.14	0.00	1,173.14	707.43
SHEARN FEDERAL 003	PDP	4.88	0.00	4.028	0.00	365.51	35.05	172.36	0.00	158.10	143.04
KORCZAK FED. #01	PBP	203.11	272.57	22.342	29.98	2,353.34	229.25	219.42	17.04	1,887.63	1,093.00
East Lusk 1 Fed #2H	PUD	192.93	331.33	69.455	119.28	6,831.59	831.41	445.57	2,493.75	3,060.86	1,631.89
KORCZAK FED. PUD #1	PUD	203.41	272.98	22.375	30.03	2,356.90	229.60	211.30	340.80	1,575.20	782.72
PUTNAM Field											
FIELDS 4-1	PDP	0.00	119.44	0.000	4.48	13.09	1.26	4.21	0.00	7.63	3.65
SERBIN Field	**Total**	**37.07**	**87.65**	**18.85**	**43.98**	**1,936.19**	**145.11**	**955.56**	**0.00**	**835.52**	**566.55**
CARLESTON 1	PDP	2.17	0.00	1.235	0.00	109.64	7.78	65.77	0.00	36.08	28.13
CARLESTON, HERBERT 3	PDP	2.93	9.52	1.788	5.81	193.49	14.75	92.47	0.00	86.27	66.54
HERN 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KASPER 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LORENZ 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MARQUIS #7 7	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MENZEL 1	PDP	7.87	0.00	4.582	0.00	406.67	28.87	158.74	0.00	219.06	126.37
MERSIOVSKY 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MILROSE-LORENZ 4	PDP	1.85	5.10	0.348	0.96	36.58	2.76	9.73	0.00	24.09	17.17
MILROSE-MARQUIS A 3	PDP	2.39	7.40	0.373	1.16	40.02	3.04	13.41	0.00	23.57	16.33
MILROSE-MARQUIS B 4	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MILROSE-VAHRENKAMP 1	PDP	1.11	2.83	0.162	0.41	16.88	1.27	7.62	0.00	7.99	6.21
MOERBE 5	PDP	2.69	0.00	1.147	0.00	101.83	7.23	51.74	0.00	42.86	30.39
MOERBE, VICTOR 3	PDP	0.13	1.19	0.097	0.87	13.86	1.14	11.81	0.00	0.92	0.88
NITSCHE, R.J. 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NORTH AMERICAN WEISE 1	PDP	0.13	0.39	0.074	0.22	7.84	0.60	6.08	0.00	1.17	1.12
PETERS #5	PDP	1.45	6.94	0.828	3.97	97.28	7.60	66.36	0.00	23.32	17.50
PETERS ‘C’ 9	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETERS 8	PDP	2.04	5.66	1.534	4.24	161.51	12.20	66.07	0.00	83.23	65.69

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All Cases **PGH Petroleum & Environmental Engineers, L.L.C.** Date : 3/2/2012
Time : 9:49:01AM

Economic Information File : oint Reserves 2012-01.Phd

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
S & M ENERGY-LORENZ 3	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S & M ENERGY-MARQUIS 6	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S & M ENERGY-MOERBE 2	PDP	0.74	3.40	0.409	1.88	47.54	3.70	25.16	0.00	18.67	15.68
S & M ENERGY-PETERS B 7	PDP	6.63	11.11	3.535	5.92	349.19	25.82	172.52	0.00	150.85	88.27
S&M ENERGY-DEAN STUESSY -E- 7	PDP	0.00	7.64	0.000	4.07	24.41	2.44	16.70	0.00	5.26	4.57
S&M ENERGY-DEAN STUESSY A 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY B 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY C 4	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY D 5	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-HERBERT STUESSY -A- 6	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-HERBERT STUESSY 3	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-PETERS A	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-SPRETZ 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-SPRETZ A 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SCOTT PETROLEUM-PETERS A 6	PDP	0.08	0.46	0.058	0.35	7.22	0.57	6.32	0.00	0.33	0.32
STEINBACH 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STEINBACH ET AL 1	PDP	2.16	12.35	0.994	5.68	122.30	9.67	55.78	0.00	56.85	39.60
URBAN #2 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
URBAN #3 3	PDP	2.11	10.31	1.455	7.10	171.66	13.42	112.04	0.00	46.20	34.46
URBAN 1	PDP	0.58	3.36	0.230	1.32	28.28	2.24	17.23	0.00	8.81	7.34
WACHSMANN 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SERBIN (TAYLOR SAND) Field	**Total**	**9.24**	**13.94**	**2.36**	**2.06**	**221.44**	**16.08**	**81.07**	**0.00**	**124.29**	**88.23**
FISCHER #02	PDP	7.28	13.94	1.074	2.06	107.64	8.00	14.65	0.00	84.99	63.21
MERSLOVSKY #01	PDP	1.96	0.00	1.282	0.00	113.81	8.08	66.42	0.00	39.30	25.01
SPRABERRY Field	**Total**	**164.89**	**424.15**	**12.04**	**37.44**	**1,233.35**	**91.12**	**452.26**	**0.00**	**689.97**	**342.60**
BUCHANAN -L- Lease	PDP	37.39	200.05	3.799	20.32	414.38	31.37	179.65	0.00	203.36	112.86
BUCHANAN M 1	PDP	13.70	72.60	1.392	7.38	150.93	11.43	59.57	0.00	79.93	55.44
BUCHANAN P 1	PDP	8.30	24.91	0.844	2.53	86.78	6.40	28.29	0.00	52.09	43.41
MCCLINTIC -A- 1	PDP	105.50	126.60	6.003	7.20	581.27	41.93	184.75	0.00	354.59	130.90
SPRABERRY (TREND AREA) Field	**Total**	**317.36**	**820.54**	**27.58**	**74.98**	**2,769.88**	**203.82**	**741.65**	**528.00**	**1,296.41**	**399.56**
BUCHANAN -L- PUD #01	PUD	75.05	222.89	7.625	22.65	771.79	56.96	276.93	150.00	287.90	117.79
BUCHANAN -M- PUD #01	PUD	69.01	204.96	7.012	20.82	706.09	52.14	160.85	150.00	343.10	110.58
BUCHANAN -M- PUD #02	PUD	69.01	204.96	7.012	20.82	706.09	52.14	160.86	150.00	343.09	93.72
MCCLINTIC -A- PUD #01	PUD	104.30	187.73	5.934	10.68	585.90	42.58	143.01	78.00	322.31	77.47

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All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Date : 3/2/2012
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File : oint Reserves 2012-01.Phd

Economic Information

Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
SULIMAR Field											
QUINOCO SULIMAR 001	PDP	60.20	0.00	51.473	0.00	4,591.23	440.30	1,343.76	0.00	2,807.18	1,366.15
SULIMAR (QUEEN) Field											
QUINOCO SULIMAR PUD #01	PUD	27.11	6.59	23.182	5.63	2,090.94	200.78	855.18	400.00	634.99	177.66
TULETA, W. Field											
STAUSS 1	PDP	0.00	51.28	0.000	1.77	6.57	0.66	5.45	0.00	0.46	0.46

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– One-Line Summary –
Value Sort

Sort by
PW 10%

All Cases

PGH Petroleum & Environmental Engineers, L.L.C.

Economic Information

Date : 3/2/2012
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Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
Proved Rsv Class	**Total**	**3,424.42**	**8,037.26**	**1,006.07**	**1,570.31**	**99,525.66**	**9,513.30**	**27,770.07**	**4,923.59**	**57,318.70**	**31,327.05**
East Lusk 1 Fed #1H	PDP	315.59	378.71	113.612	136.33	10,930.04	1,327.69	687.11	0.00	8,915.24	7,039.42
APACHE BROMIDE SAND UNIT	PDP	755.83	354.29	145.951	68.41	13,729.85	1,317.38	6,527.65	0.00	5,884.82	3,342.66
JENNINGS FEDERAL 001	PDP	142.57	47.80	103.365	34.65	9,571.82	919.53	1,863.75	0.00	6,788.55	2,729.46
NORTH BLOCK 12 UNIT	PDP	112.62	0.00	94.216	0.00	8,448.87	599.87	4,058.13	0.00	3,790.87	2,133.27
FLYING M SOUTH (ABO) PUD #01	PUD	215.94	360.61	63.572	106.16	6,303.81	609.35	432.35	1,099.00	4,163.11	2,131.42
KINNEY ST #38	PDP	99.15	0.00	86.755	0.00	7,608.18	651.26	1,500.00	0.00	5,456.92	1,821.78
East Lusk 1 Fed #2H	PUD	192.93	331.33	69.455	119.28	6,831.59	831.41	445.57	2,493.75	3,060.86	1,631.89
QUINOCO SULIMAR 001	PDP	60.20	0.00	51.473	0.00	4,591.23	440.30	1,343.76	0.00	2,807.18	1,366.15
RUSH SPRINGS MEDRANO UNIT	PDP	310.20	26.27	50.221	4.25	4,738.36	454.65	2,549.97	0.00	1,733.74	1,306.34
KORCZAK FED. #01	PBP	203.11	272.57	22.342	29.98	2,353.34	229.25	219.42	17.04	1,887.63	1,093.00
NORTH BILBREY 7 FEDERAL 001	PDP	0.00	1,352.89	0.000	490.33	2,681.69	302.74	442.34	0.00	1,936.60	826.22
KORCZAK FED. PUD #1	PUD	203.41	272.98	22.375	30.03	2,356.90	229.60	211.30	340.80	1,575.20	782.72
SHADE 0	PDP	29.89	164.40	22.972	124.70	3,178.59	259.88	1,627.32	0.00	1,291.39	758.61
KORCZAK FED. #01	PDP	131.70	176.74	14.487	19.44	1,525.93	148.65	204.14	0.00	1,173.14	707.43
ARROWHEAD #1-49	PDP	21.48	0.00	12.860	0.00	1,175.01	83.43	476.03	0.00	615.56	438.35
ELKHORN A ST 015658A 15	PDP	16.60	0.00	13.696	0.00	1,209.62	103.54	411.30	0.00	694.78	299.61
KINNEY ST #38	PDP	9.59	0.00	8.387	0.00	735.53	62.96	160.97	0.00	511.60	291.68
CLEMMONS SUNBURST FEDERAL 001	PDP	17.75	41.71	5.226	12.28	513.00	49.53	177.70	0.00	285.77	209.06
MERCURY FEE #01	PBP	0.00	1,578.81	0.000	116.83	412.73	44.12	61.91	45.00	261.70	208.01
QUINOCO SULIMAR PUD #01	PUD	27.11	6.59	23.182	5.63	2,090.94	200.78	855.18	400.00	634.99	177.66
HOSS RA SUH;CUSHMAN 002	PDP	6.47	1,078.67	0.593	98.91	468.43	39.42	134.50	0.00	294.50	167.00
STATE OF TEXAS -Z- 0	PDP	13.82	0.00	12.096	0.00	1,109.09	78.75	830.59	0.00	199.75	166.70
SHEARN FEDERAL 003	PDP	4.88	0.00	4.028	0.00	365.51	35.05	172.36	0.00	158.10	143.04
ELKHORN 14	PDP	5.00	0.00	4.374	0.00	386.33	33.07	126.55	0.00	226.71	142.82
MCCLINTIC -A- 1	PDP	105.50	126.60	6.003	7.20	581.27	41.93	184.75	0.00	354.59	130.90
MENZEL 1	PDP	7.87	0.00	4.582	0.00	406.67	28.87	158.74	0.00	219.06	126.37
BUCHANAN -L- PUD #01	PUD	75.05	222.89	7.625	22.65	771.79	56.96	276.93	150.00	287.90	117.79
BUCHANAN -L- Lease	PDP	37.39	200.05	3.799	20.32	414.38	31.37	179.65	0.00	203.36	112.86
BUCHANAN -M- PUD #01	PUD	69.01	204.96	7.012	20.82	706.09	52.14	160.85	150.00	343.10	110.58
BUCHANAN -M- PUD #02	PUD	69.01	204.96	7.012	20.82	706.09	52.14	160.86	150.00	343.09	93.72
S & M ENERGY-PETERS B 7	PDP	6.63	11.11	3.535	5.92	349.19	25.82	172.52	0.00	150.85	88.27
MCCLINTIC -A- PUD #01	PUD	104.30	187.73	5.934	10.68	585.90	42.58	143.01	78.00	322.31	77.47
CARLESTON, HERBERT 3	PDP	2.93	9.52	1.788	5.81	193.49	14.75	92.47	0.00	86.27	66.54
PETERS 8	PDP	2.04	5.66	1.534	4.24	161.51	12.20	66.07	0.00	83.23	65.69

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Lease Name	Rsv Cat	Gross Rem Resv Oil Mbbl	Gross Rem Resv Gas MMcf	Net Rem Resv Oil Mbbl	Net Rem Resv Gas MMcf	Net Rev M$	Sev + Adv Tax M$	Oper Exp M$	Capital Costs M$	FNR BTax M$	Disc FNR, BTax @ 10%, M$
FISCHER #02	PDP	7.28	13.94	1.074	2.06	107.64	8.00	14.65	0.00	84.99	63.21
BUCHANAN M 1	PDP	13.70	72.60	1.392	7.38	150.93	11.43	59.57	0.00	79.93	55.44
BUCHANAN P 1	PDP	8.30	24.91	0.844	2.53	86.78	6.40	28.29	0.00	52.09	43.41
STEINBACH ET AL 1	PDP	2.16	12.35	0.994	5.68	122.30	9.67	55.78	0.00	56.85	39.60
URBAN #3 3	PDP	2.11	10.31	1.455	7.10	171.66	13.42	112.04	0.00	46.20	34.46
MOERBE 5	PDP	2.69	0.00	1.147	0.00	101.83	7.23	51.74	0.00	42.86	30.39
CARLESTON 1	PDP	2.17	0.00	1.235	0.00	109.64	7.78	65.77	0.00	36.08	28.13
MERSLOVSKY #01	PDP	1.96	0.00	1.282	0.00	113.81	8.08	66.42	0.00	39.30	25.01
PETERS #5	PDP	1.45	6.94	0.828	3.97	97.28	7.60	66.36	0.00	23.32	17.50
MILROSE-LORENZ 4	PDP	1.85	5.10	0.348	0.96	36.58	2.76	9.73	0.00	24.09	17.17
MILROSE-MARQUIS A 3	PDP	2.39	7.40	0.373	1.16	40.02	3.04	13.41	0.00	23.57	16.33
S & M ENERGY-MOERBE 2	PDP	0.74	3.40	0.409	1.88	47.54	3.70	25.16	0.00	18.67	15.68
HERMES FEE 001	PDP	0.00	75.74	0.000	8.33	28.07	3.00	9.37	0.00	15.71	11.72
URBAN 1	PDP	0.58	3.36	0.230	1.32	28.28	2.24	17.23	0.00	8.81	7.34
MILROSE-VAHRENKAMP 1	PDP	1.11	2.83	0.162	0.41	16.88	1.27	7.62	0.00	7.99	6.21
S&M ENERGY-DEAN STUESSY -E- 7	PDP	0.00	7.64	0.000	4.07	24.41	2.44	16.70	0.00	5.26	4.57
FIELDS 4-1	PDP	0.00	119.44	0.000	4.48	13.09	1.26	4.21	0.00	7.63	3.65
NORTH AMERICAN WEISE 1	PDP	0.13	0.39	0.074	0.22	7.84	0.60	6.08	0.00	1.17	1.12
MOERBE, VICTOR 3	PDP	0.13	1.19	0.097	0.87	13.86	1.14	11.81	0.00	0.92	0.88
STAUSS 1	PDP	0.00	51.28	0.000	1.77	6.57	0.66	5.45	0.00	0.46	0.46
SCOTT PETROLEUM-PETERS A 6	PDP	0.08	0.46	0.058	0.35	7.22	0.57	6.32	0.00	0.33	0.32
SUNBURST SPENCE FEDERAL 002	PDP	0.02	0.15	0.006	0.04	0.67	0.06	0.59	0.00	0.01	0.01
CHMELAR, EUGENE -A- 1 L	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CRONOS FEE 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HERN 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HOSS 7800 RA SUA;CUSHMAN 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KASPER 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LORENZ 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MARQUIS #7 7	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MERCURY FEE 001	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MERSIOVSKY 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MILROSE-MARQUIS B 4	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NITSCHE, R.J. 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETERS ‘C’ 9	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S & M ENERGY-LORENZ 3	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S & M ENERGY-MARQUIS 6	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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S&M ENERGY-DEAN STUESSY A 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY B 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY C 4	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-DEAN STUESSY D 5	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-HERBERT STUESSY -A-6	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-HERBERT STUESSY 3	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-PETERS A	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-SPRETZ 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
S&M ENERGY-SPRETZ A 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
STEINBACH 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
URBAN #2 2	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WACHSMANN 1	PDP	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00	0.00

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