UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012

or

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

Commission File No. 000-18774

SPINDLETOP OIL & GAS CO.
(Exact name of registrant as specified in its charter)

Texas	**75-2063001**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
12850 Spurling Rd., Suite 200, Dallas, TX	**75230**
(Address of principal executive offices)	(Zip Code)

(972) 644-2581
(Registrant's telephone number, including area code)

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

Title of each Class	Name of each exchange on which registered
None	**N/A**

Securities registered pursuant to Section 12(g) of the Act: **Common Stock, $0.01 par value**

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

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

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

Indicate by check mark whether the registrant (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 Company was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§293.405 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 the Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer or a smaller reporting company. See definitions of “large accelerated filer”, “accelerated filer”, and “smaller reporting company” in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer [ ] Accelerated filer [ ]

Non-accelerated filer [ ] Smaller reporting company [X]

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

State 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 last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter.

$3,661,341 based upon a total of 1,760,260 shares held as of June 30, 2012 by persons believed to be non-affiliates of the Registrant; the basis of the calculation does not constitute a determination by the Registrant as defined in Rule 405 of the Securities Act of 1933, as amended, that such calculation, if made as of a date within 60 days of this filing, would yield a different value.

APPLICABLE ONLY TO REGISTRANTS INVOLVED IN BANKRUPTCY PROCEEDINGS DURING THE PRECEDING FIVE YEARS:

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes [ ] No [ ]

(APPLICABLE ONLY TO CORPORATE REGISTRANTS)

Indicate the number of shares outstanding of each of the issuer's classes of common, as of the latest practicable date.

Common Stock, $0.01 par value	**6,936,269**
(Class)	(Outstanding at April 1 2013)

DOCUMENTS INCORPORATED BY REFERENCE

None

PART I

Item 1. Description of Business

GENERAL

Spindletop Oil & Gas Co. is an independent oil and gas company engaged in the exploration, development, production and acquisition of oil and natural gas; the rental of oilfield equipment; and through one of its subsidiaries, the gathering and marketing of natural gas. The terms the "Company", "We", "Us" or “Spindletop” are used interchangeably herein to refer to Spindletop Oil & Gas Co. (“SOG”) and its wholly owned subsidiaries, Spindletop Drilling Company ("SDC"), and Prairie Pipeline Co. (“PPC”).

The Company has focused its oil and gas operations principally in Texas, although we operate properties in six states including: Texas, Oklahoma, New Mexico, Louisiana, Alabama and Arkansas. We operate a majority of our projects through the drilling and production phases. Our staff has a great deal of experience in the operations arena. We have traditionally leveraged the risks associated with drilling by obtaining industry partners to share in the costs.

In addition, the Company, through PPC, owns approximately 26.1 miles of pipelines located in Texas, which are used for the gathering of natural gas. These gathering lines are located in the Fort Worth Basin and are being utilized to transport the Company's natural gas as well as natural gas produced by third parties.

Website Access to Our Reports

We make available free of charge through our website, www.spindletopoil.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission. Information on our website is not a part of this report.

Operating Approach

We believe that a major attribute of the Company is its long history with, and extensive knowledge of, the Fort Worth Basin of Texas. Our technical staff has an average of over 20 years oil and gas experience, most of it in the Fort Worth Basin.

One of our strengths has been the ability of the Company to look at cost effective ways to grow our production. We have traditionally increased our reserve base in one of two ways. Initially, in the 1970s and 1980s, the Company obtained its production through an exploration and development drilling program focused principally in the Fort Worth Basin of North Texas. Today, the Company has retained many of these wells as producing properties and holds a large amount of acreage by production in that Basin.

From the 1990s through 2003, the Company took advantage of the lower product prices by cost effectively adding to its reserve base through value-priced acquisitions. We found that through selective purchases we could make producing property acquisitions that were more cost effective than drilling.

During this time period, the Company acquired a large number of operated and non-operated oil and gas properties in various states.

From 2003 through the fourth quarter of 2008, we returned our focus to a strategy of development drilling with an emphasis on our Barnett Shale acreage. Since 2009, we split our focus by looking for value-priced acquisitions combined with development drilling prospects. In the current economic climate, we are continuing our efforts to acquire producing properties and taking a more conservative approach to development of our leasehold acreage. We are looking at growth through acquisitions and limited drilling. With current lower natural gas prices and high costs to produce, we believe that it is prudent to carefully evaluate all our options and make sure that each transaction can be supported in today’s lower price environment.

Strategic Business Plans

One of our key strategies is to enhance shareholder value through implementation of plans for controlled growth and development. The Company's long-term focus is to grow its oil and gas production through a strategic combination of selected property acquisitions, to the extent feasible, and an exploration and development program primarily based on developing its leasehold acreage. Additionally, the Company plans to continue to rework existing wells to increase production and reserves.

The Company's primary area of operation has been in the State of Texas with an emphasis in the geological province known as the Fort Worth Basin. We plan to continue to focus on operations in Texas, and we want to capitalize on our strengths which include an extensive knowledge of the various reservoirs in Texas, experience in operations in this geographic area, development of lease holdings, and utilization of existing infrastructure to minimize costs.

The Company will continue to generate and evaluate prospects using its own technical staff. The Company intends to fund operations primarily from cash flow generated by operations.

Project Significant Areas

The Company owns various interests in wells located in 15 states and the Company's operations are currently located in 6 of those states which include Alabama, Arkansas, Louisiana, Oklahoma, New Mexico and Texas.

The Company holds approximately 96,925 gross acres under lease in 15 states. The majority of the leases are held by production. A breakout of the Company's leasehold acreage by geographic area is as follows:

	Operated Properties		Non-Operated Properties		Total		Percent of Total	
Geographic Area	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
North Texas (1)	7,700	7,184	2,254	236	9,954	7,420	10.27%	34.14%
East Texas	2,802	2,342	9,654	744	12,456	3,086	12.85%	14.20%
Gulf Coast Texas	3,943	2,345	2,930	223	6,873	2,568	7.09%	11.82%
West Texas	1,109	821	2,664	109	3,773	930	3.89%	4.28%
Texas Panhandle	680	680	1,360	80	2,040	760	2.10%	3.50%
Alabama	1,160	634	2,509	183	3,669	817	3.79%	3.76%
Arkansas	2,296	1,960	4,329	116	6,625	2,076	6.84%	9.55%
Louisiana	838	551	2,938	138	3,776	689	3.90%	3.17%
New Mexico	1,684	997	360	4	2,044	1,001	2.11%	4.61%
Oklahoma	317	184	33,405	1,020	33,722	1,204	34.79%	5.54%
California	—		892	6	892	6	0.92%	0.03%
Colorado	—		1,200	64	1,200	64	1.24%	0.29%
Kansas	—		640	184	640	184	0.66%	0.85%
Michigan	—		240	6	240	6	0.25%	0.03%
Mississippi	—		140	6	140	6	0.14%	0.03%
Montana	—		3,090	152	3,090	152	3.19%	0.70%
North Dakota	—		1,262	138	1,262	138	1.30%	0.64%
Utah	—		2,729	487	2,729	487	2.82%	2.24%
Wyoming	—		1,800	134	1,800	134	1.86%	0.62%
Total	22,529	17,698	74,396	4,030	96,925	21,728	100.01%	100.00%

(1) North Texas includes the Fort Worth Basin & Bend Arch
The majority of the Company's net acres (67.94%) are located in Texas.

A breakout of the Company's most significant oil and gas reserves by geographic area is as follows:

	BOE	
North Texas including the Fort Worth Basin & Bend Arch	873,337	55.01%
East Texas	225,925	14.23%
Panhandle Texas	73,592	4.64%
West Texas	72,937	4.59%
Gulf Coast Texas	35,450	2.23%
Total Texas	1,281,240	80.71%
Alabama	97,955	6.17%
Oklahoma	77,477	4.88%
New Mexico	65,563	4.13%
Louisiana	44,213	2.78%
Montana	15,173	0.96%
North Dakota	2,008	0.13%
Kansas	1,815	0.11%
Wyoming	1,795	0.11%
Michigan	207	0.01%
California	107	0.01%
Total Other States	306,313	19.29%
Total	1,587,553	100.00%

North Texas - Fort Worth Basin & Bend Arch

The Fort Worth Basin-Bend Arch Province has been the focal point of the Company since its inception. Our technical personnel have an average of 20 years of exploration, drilling, completing, and production experience extracting natural gas and oil from both conventional and unconventional hydrocarbon deposits found across the basin. Furthermore, the Company maintains comprehensive and extensive dossiers of geologic and engineering data gathered from the province. Exploration and development drilling for hydrocarbons across the Fort Worth Basin-Bend Arch Province continue to remain strong.

The Fort Worth Basin-Bend Arch Province is a major United States onshore natural gas-prone expanse containing multiple pay zones that range in depth from one thousand to nine thousand (1,000-9,000) feet. Improved technical advances in fracturing and stimulation technologies, have helped unlock natural gas and oil reserves from the hydrocarbon bearing Barnett Shale Formation; and thus, continue to bolster vigorous exploration and development activities that target these conventional and unconventional reservoir reserves throughout the province.

The Barnett Shale is a thick blanket type natural gas bearing stratigraphic zone found throughout the Fort Worth Basin-Bend Arch Province. The natural gas reserves in place are significant; however, as a consequence of the extreme low permeability character of the shales, it has been technically challenging to produce these reserves. According to the United States Geological Survey assessment, an estimated 26.7 trillion cubic feet (TCF) of undiscovered natural gas, 98.5 MMBO of undiscovered oil, as well as a mean of 1.1 BBNGL of undiscovered natural gas liquids reserves remain within the 54,000 square mile Fort Worth Basin-Bend Arch Province. More than 98 percent or approximately 26.2 TCF of the undiscovered natural gas is contained in the organic-rich Mississippian Barnett Shale. Combined, recent advances in hydraulic fracturing, completion procedures, as well as refined horizontal well drilling technologies continue to enable economic recovery of natural gas reserves from tight-gas reservoirs throughout the Fort Worth Basin-Bend Arch Province. Undiscovered conventional reservoir natural gas reserves are estimated to be 467 billion cubic feet of gas (BCFG) the majority of which is dissolved in conventional oil accumulations (source: United States Geological Survey Energy Resource Program).

The Company has 9,954 gross acres under lease across the prolific Fort Worth Basin-Bend Arch Province the majority of which, is held by production from the more shallow producing zones. The Company uses recent and emerging technologies, as well as proven industry practices to develop and produce oil and natural gas from its properties. Additionally, the Company has a dedicated and well-trained team of employees and professional staff that continually seek out low-risk profitable drilling and acquisition opportunities throughout the Fort Worth Basin-Bend Arch Province.

Texas Panhandle

During the first quarter of 2012, the Company participated for a 15% non-operated working interest and an 11.25% net revenue interest in the Pope 140 #3H well in Ochiltree County, Texas. The well was spudded on February 21, 2012, and drilled to a depth of 10,988 ft. The well was completed on April 21, 2012, in the Cleveland Formation. The well had initial potential flowing (IPF) of 198 bopd, 1,685 mcfgpd, and 357 bswpd on April 24, 2012.

East Texas

The Company has participated in several new horizontal wells drilled under farmout agreements the Company granted to a third party non-related operator on its leasehold acreage block on its Leona East Prospect located in the south central portion of Leon County, Texas.

During the fourth quarter of 2011, the Company participated for a 5% non-operated working interest and a 3.75% net revenue interest in the Easterling #1H well in Leon County, Texas. The well was spudded on January 6, 2012, and drilled to a depth of 13,636 ft. On February 20, 2012, the well was completed in the Woodbine formation. The well had an initial potential flowing (IPF) of 516 bopd, 1 mcfgpd and 643 bswpd on April 29, 2012.

During the fourth quarter of 2011, the Company participated for a 3.2425% non-operated working interest and a 2.431875% net revenue interest in the Patrick #1H well in Leon County, Texas. This well was spudded on October 29, 2011, in the Halliday field, and drilled to a depth of 14,872 ft. The well was completed on February 20, 2012, in the Woodbine formation and began producing from a perforated interval from 7,742 ft. to 14,692 ft. during the first quarter of 2012 at an average rate of 476 bopd, 182 mcfgpd, and 422 bswpd for the first full month.

During the second quarter of 2012, the Company participated for a 14.5833% non-operated working interest and a 10.9375% net revenue interest in the A. M. Easterling-Gresham SA #1H well in Leon County, Texas. On June 29, 2012, the well was spudded in the Halliday field, and drilled to a depth of 14,274 ft. The well was cased and completed in the Woodbine formation on August 23, 2012. The operator of the well reported that the well tested on a 32/64th choke at a rate of 919 bopd and 139 mcfgpd from the Woodbine formation. The well has a 6,730 ft. lateral, was completed with 24 stages of fracturing, and is perforated from 7,452 ft. to 14,140 ft.

During the third quarter of 2012, the Keeling #1H well was spudded in the Halliday field in Leon County, Texas. The well reached a total depth of 15,985 ft. in the Woodbine formation. The well was cased to a depth of 14,072 ft. on September 15, 2012, was completed on November 28, 2012, and had an initial potential flowing (IPF) of 716 bopd and 816 bswpd with a FTP of 410 psi on a 24/64^{th} choke on December 5, 2012.
The Company owns approximately a 17% working interest in the well with specific interest to be determined upon completion of a division order title opinion for the well. Additional well locations have been permitted and are currently being permitted in this field by the operator, which the Company will have additional rights of participation in for yet to be determined amounts and which will vary depending upon the drilling locations for those wells and the Company’s leasehold positions with respect to those wells. One of the additional wells that as already been drilled and completed is the Keeling #2H well, on which the operator reported an initial potential test on December 10, 2012, of 504 bopd and 574 bswpd with a FTP of 450 psi on a 20/64^{th} choke from the Woodbine formation. The company is awaiting further title information from the operator for a determination of its percentage participation in the Keeling #2H well as well as for the additional wells being permitted by the operator in this field.

North Texas

Effective July 1, 2012, the Company acquired operations and a 100% working interest and an 80.576743% net revenue interest in five natural gas wells in the Newark East Field in Denton County, Texas. The Wyatt #1 through #5 wells were producing from the Barnett Shale formation at a rate of 40 mcfgpd, 59 mcfgpd, 48 mcfgpd, 62 mcfgpd and 77 mcfgpd, respectively, as of the effective date.

South Texas

During the third quarter of 2011, the Company drilled two wells with 100% working interest and 60.83984% net revenue interest on its Hynes lease in Bee County, Texas. The Hynes #29R and #30R, both in the Papalote field, were drilled and cased to test the Catahoula Formation at an approximate depth of 3,453 ft. Both wells are currently shut-in.

West Texas

Effective October 1, 2012, the Company acquired operations and a 26.5% working interest and a 17.7153% net revenue interest in the Le Petit Pois #1 well in the Dewey Lake, South field in Glasscock County, Texas. The well was producing 59 mcfgpd and no water from a perforated interval at 10,062 ft. to 10,204 ft. in the Strawn formation as of the effective date.

On November 27, 2012, the Company elected to participate for a 4.68750% non-operated working interest and a 3.28125% net revenue interest in the drilling of the Miles #28 well in the Fuhrman-Mascho field in Andrews County, Texas. The well was spudded on November 14, 2012, and reached a total depth of 4,912 ft. on November 18, 2012. The well was perforated in the San Andres Formation from 4,556 ft. to 4,790 ft., fractured, and had an initial potential flowing of 54 bopd, 4 mcfgpd, and 42 bswpd on January 7, 2013.

Effective December 1, 2012, the Company elected to participate for a 4.68750% non-operated working interest and a 3.28125% net revenue interest in the drilling of the Miles #29 well in the Fuhrman-Mascho field in Andrews County, Texas. Subsequent to the year end, the well was spudded on February 20, 2013, and reached a total depth of 4,903' on February 24, 2013. The well was cased and is currently awaiting completion.

Alabama

During the fourth quarter of 2011, the Company elected to participate in the drilling of the Jones #28-6 well for a 10.2% non-operated working interest and a 7.653675% net revenue interest, in the Little Cedar Creek field in Conecuh County, Alabama. The well was drilled to a total depth of 11,750 ft. and cased. The well began producing on January 26, 2012, from a perforated interval at 11,385 ft. to 11,389 ft. in the Smackover Formation, with an initial rate of 98 bopd, 122 mcfgpd, and no water.

Effective April 11, 2012, the Company participated for a 10.2049% non-operated working interest and a 7.653675% net revenue interest in the drilling of the Cedar Creek Land and Timber 28-15 #1 well in the Little Cedar Creek field in Conecuh County, Alabama. The well was drilled to a total depth of 11,745 ft. and completed on July 31, 2012, in the Smackover Formation. On August 24, 2012, the well was flow tested at a rate of 351 bopd and 401 mcfgpd and no water on an 18/64th choke with FTP of 380 psi.

Effective July 30, 2012, the Company participated for a 10.2049% non-operated working interest and a 7.653675% net revenue interest in the drilling of the Cedar Creek Land and Timber 27-13 #1 well in the Little Cedar Creek field in Conecuh County, Alabama. The well was drilled to a total depth of 11,800 ft. and was cased on September 3, 2012. The well was perforated in the Smackover from 11,480-11,490 ft. then acidized with 2,000 gals of 15% FE acid. The well was placed into production on November 10, 2012, at an initial rate of 86 bopd, 75 mcfgpd and 48 bswpd.

Montana

Effective June 1, 2012, the Company acquired a 7.4031% non-operated working interest and a 5.9225% net revenue interest in the Hage #44-20 well in the Diamond Point field in Roosevelt County, Montana. The well was producing approximately 10 bopd and 261 bswpd from a perforated interval of the Red River Formation as of the effective date.

Also effective June 1, 2012, the Company acquired a 7.4031% non-operated working interest and a 5.9225% net revenue interest in the Consolidated State #42-20 well in the Diamond Point field in Roosevelt County, Montana. The well was producing approximately 22 bopd, 7 mcfgpd, and 408 bswpd from perforated intervals of the Interlake and Red River formations as of the effective date.

The Company also acquired a 7.4031% non-operated working interest in the Consolidated State SWD well in Roosevelt County, Montana, in the Diamond Point Field. The well is being utilized to dispose of produced water from the State #42-20 and the Hage #44-20 wells.

Oklahoma

Effective January 1, 2012, the Company acquired operations and a 22.6875% working interest and a 16.4681% net revenue interest the Weryackwe #1-28 well in the Apache Townsite field in Caddo County, Oklahoma. The well was producing approximately 42 mcfgpd and 0.4 bswpd from a perforated interval from 4,470 ft. to 4,702 ft. in the Arbuckle formation as of the effective date.

For all of the above wells, the Company cautions that the initial production rates of a newly completed well or newly recompleted well or the production rates at the effective date of acquisition may not be an indicator of stabilized production rates or an indicator of the ultimate recoveries obtained.

Oil and Natural Gas Reserves

The net proved crude oil and gas reserves of the Company as of December 31, 2012 were 498,720 barrels of oil and condensate and 6.533 BCFG of natural gas. Based on SEC guidelines, the reserves were classified as follows:

	Barrels of Oil	BCF of Gas
Proved Developed Producing	467,980	6.506
Proved Developed Non-Producing	30,740	0.027
Proved Undeveloped	—	—
Total Proved Reserves	498,720	6.533

Only reserves that fell within the Proved classification were considered. Other categories such as Probable or Possible Reserves were not considered. No value was given to the potential future development of behind pipe reserves, untested fault blocks, or the potential for deeper reservoirs (other than Barnett Shale proved undeveloped reserves directly offset by producing wells which are slated for drilling in the next five years) underlying the Company's properties. Shut-in uneconomic wells and insignificant non-operated interests were excluded.

On a BOE (barrel of oil equivalent) basis (6 MCF/BOE), the net reserves are:

	Barrels of Oil Equivalent (BOE)	
Natural Gas Reserves	1,088,833	69%
Oil Reserves	498,720	31%
Total Reserves	1,587,553	100%
Proved Developed Producing	1,552,323	98%
Proved Developed Non-Producing	35,230	2%
Proved Undeveloped	—	0%
Total Proved Reserves	1,587,553	100%

The Company has operational control over the majority of these reserves and can therefore to a large extent control the timing of development and production.

	Barrels of Oil Equivalent (BOE)	
The Company's Operated Wells	1,279,272	81%
Non-Operated Wells	308,282	19%
Total	1,587,553	100%

Financial Information Relating to Industry Segments

The Company has three identifiable business segments: (1) exploration, acquisition, development and production of oil and natural gas, (2) gas gathering, and (3) commercial real estate investment. Footnote 15 to the Consolidated Financial Statements filed herein sets forth the relevant information regarding revenues, income from operations and identifiable assets for these segments.

Narrative Description of Business

The Company is engaged in the exploration, development, acquisition and production of oil and natural gas, and the gathering and marketing of natural gas. The Company is also engaged in commercial real estate leasing through leasing office space to non-related third party tenants in the Company’s corporate headquarters office building.

Principal Products, Distribution and Availability

The principal products marketed by the Company are crude oil and natural gas which are sold to major oil and gas companies, brokers, pipelines and distributors, and oil and gas properties which are acquired and sold to oil and gas development entities. Reserves of oil and gas are depleted upon extraction, and the Company is in competition with other entities for the discovery of new prospects.

The Company is also engaged in the gathering and marketing of natural gas through its subsidiary PPC, which owns 26.1 miles of pipelines and currently gathers approximately 1,345 mcfgpd. Natural gas is gathered for a fee. Substantially all of the gas gathered by the Company is gas produced from wells that the Company operates and in which it owns a working interest.

The Company owns land and a two story commercial office building in Dallas, Texas, which it uses as its principal headquarters office. The Company leases the remainder of the building to non-related third party commercial tenants at prevailing market rates.

Patents, Licenses and Franchises

Oil and gas leases of the Company are obtained from the owner of the mineral estate. The leases are generally for a primary term of three or more years, and often have extension options for an equivalent period as the original primary term for payment of additional bonus consideration. The leases customarily provide for extension beyond their primary term for as long as oil and gas are produced in commercial quantities or other operations are conducted on such leases as provided by the terms of the leases.

The Company currently holds interests in producing and non-producing oil and gas leases. The existence of the oil and gas leases and the terms of the oil and gas leases are important to the business of the Company because future additions to reserves will come from oil and gas leases currently owned by the Company, and others that may be acquired, when they are proven to be productive. The Company is continuing to purchase oil and gas leases in areas where it currently has production, and also in other areas.

Dependence on Customers

The following is a summary of significant purchasers / operators (listed by percent of total oil and natural gas sales) from oil and natural gas produced by the Company for the three-year period ended December 31, 2012:

Purchaser / Operator	2012	2011	2010
Shell Trading (US) Company	15%	20%	7%
Pruet Production Co.	9%	0%	0%
Enbridge Energy Partners	9%	22%	26%
Targa Midstream Service, LIM	8%	4%	3%
Halcon Resources Operating, Inc.	7%	0%	0%
Eastex Crude Company	6%	7%	7%
Crosstex Gulf Coast Mktg	5%	11%	16%
Panther Energy Company, LLC	4%	0%	0%
Gulfmark Energy, Inc.	4%	3%	0%
HollyFrontier Refining & Marketing LLC	3%	2%	3%
Petromax Operating Co., Inc.	3%	0%	0%
Sunoco Partners Marketing	3%	1%	1%
Encana Oil & Gas (USA), Inc.	3%	0%	0%
Enterprise Crude Oil, LLC	2%	5%	5%
Enervest Operating, LLC	2%	0%	0%
Sklar Exploration Co., LLC	2%	0%	0%
ETC Texas Pipeline	2%	2%	2%

Oil and gas is sold to approximately 100 different purchasers under market sensitive, short-term contracts computed on a month to month basis.

Except as set forth above, there are no other customers of the Company that individually accounted for more than two percent of the Company's oil and gas revenues during the three years ended December 31, 2012.

The Company currently has no hedged contracts.

Prospective Drilling Activities

The Company's primary oil and gas prospect generation and acquisition efforts have been in known producing areas in the United States with emphasis devoted to Texas.

The Company intends to use a portion of its available funds to participate in drilling activities. The Company does not own any drilling rigs and all drilling activity is performed by independent drilling contractors. The Company does not refine or otherwise process its oil and gas production.

Exploration for oil and gas is normally conducted with the Company acquiring undeveloped oil and gas leases under prospects, and carrying out exploratory drilling on the prospective leasehold with the Company retaining a majority interest in the prospect. Interests in the property are sometimes sold to key employees and associated companies at cost. Also, interests may be sold to third parties with the Company retaining an overriding royalty interest, carried working interest, or a reversionary interest.

A prospect is a geographical area designated by the Company for the purpose of searching for oil and gas reserves and reasonably expected by it to contain at least one oil or gas reservoir. The Company utilizes its own funds along with the issuance of common stock and options to purchase common stock in some limited cases, to acquire oil and gas leases covering the lands comprising the prospects. These leases are selected by the Company and are obtained directly from the landowners, as well as from landmen, geologists, other oil companies, some of whom may be affiliated with the Company, and by direct purchase, farm-in, or option agreements. After an initial test well is drilled on a property, any subsequent development drilling of such prospect will normally require the Company to fund the development activities.

Special Tax Provisions

See Footnote 8 to Consolidated Financial Statements regarding the accounting for income taxes.

Employees

The Company employs or contracts for the services of a total of approximately sixty-two people. Twenty-seven are full-time employees. The remainder are part-time employees or independent contractors. We believe that our relationships with our employees are good.

In order to effectively utilize our resources, we employ the services of independent consultants and contractors to perform a variety of professional and technical services, including in the areas of lease acquisition, land related documentation and contracts, drilling and completion work, pumping, inspection, testing, maintenance and specialized services. We believe that it can be more cost effective to utilize the services of consultants and independent contractors for some of these services.

We depend to a large extent on the services of certain key management personnel and officers, and the loss of any these individuals could have a material adverse effect on our operations. The Company does not maintain key-man life insurance policies on its employees.

Financial information about foreign and domestic operations and export sales

All of the Company's business is conducted domestically, with no export sales.

Compliance with Environmental Regulations

Our oil and natural gas operations are subject to numerous United States federal, state and local laws and regulations relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and clean-up of contaminated science. We could incur material costs, including clean-up costs, fines and civil and criminal sanctions and third party claims for property damage and personal injury as a result of violations of, or liabilities under, environmental laws and regulations. Such laws and regulations not only expose us to liability for our own activities, but may also expose us to liability for the conduct of others or for actions by us that were in compliance with all applicable laws at the time those actions were taken. In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent.

Glossary of Oil and Gas Terms

The following are abbreviations and definitions of terms commonly used in the oil and gas industry that are used in this Report. The terms defined herein may be found in this report in both upper and lower case or a combination of both.

"BBL" means a barrel of 42 U.S. gallons.

“BBNGL” means billion barrels of natural gas liquids.

“BCF” or “BCFG” means billion cubic feet.

"BOE" means barrels of oil equivalent; converting volumes of natural gas to oil equivalent volumes using a ratio of six Mcf of natural gas to one Bbl of oil.

“BOPD” means barrels of oil per day.

"BTU" means British Thermal Units. British Thermal Unit means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

“BSWPD” means barrels of salt water per day.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Development Well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a strata graphic horizon known to be productive.

"Dry Hole" or "Dry Well" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

"Farm-Out" means an agreement pursuant to which the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" and the assignor issues a "farm-out."

"Farm-In" see "Farm-Out" above.

"Gas" means natural gas.

"Gross" when used with respect to acres or wells, refers to the total acres or wells in which we have a working interest.

"Infill Drilling" means drilling of an additional well or wells provided for by an existing spacing order to more adequately drain a reservoir.

"MCF" or “MCFG” means thousand cubic feet.

“MCFGPD” means thousand cubic feet of gas per day.

"MCFE" means MCF of natural gas equivalent; converting volumes of oil to natural gas equivalent volumes using a ratio of one BBL of oil to six MCF of natural gas.

“MMBO” means million barrels of oil.

"MMBTU" means one million BTUs.

"Net" when used with respect to acres or wells, refers to gross acres or wells multiplied, in each case, by the percentage working interest owned by the Company.

"Net Production" means production that is owned by the Company less royalties and production due others.

"Non-Operated" or "Outside Operated" means wells that are operated by a third party.

"Operator" means the individual or company responsible for the exploration, development, production and management of an oil or gas well or lease.

“Overriding Royalty” means a royalty interest which is usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"Present Value" ("PV") when used with respect to oil and gas reserves, means the estimated future gross revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the SEC, net of estimated production and future development costs as of the date of estimation without future escalation, and discounted using an annual discount rate of 10%. Prices are not escalated and are computed using a 12-month average price, calculated as the un-weighted arithmetic average of the first-day-of-the month price for each month of the year (except to the extent a contract specifically provides otherwise). No effect is given to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization.

"Productive Wells" or "Producing Wells" consist of producing wells and wells capable of production, including wells waiting on pipeline connections.

"Proved Developed Reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery will be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

"Proved Reserves" means the estimated quantities of crude oil and natural gas which upon analysis of geological and engineering data appear 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 consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

> (i) Reservoirs are considered proved if either actual production or conclusive formation tests support economic producibility. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil and natural gas, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (C) crude oil and natural gas that may occur in undrilled prospects; and (D) crude oil and natural gas that may be recovered from oil shales, coal, gilsonite and other such resources.

"Proved Undeveloped Reserves" means reserves that are recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

"Recompletion" means the completion for production of an existing well bore in another formation from that in which the well has been previously completed.

"Reserves" means proved reserves.

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

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

“TCF” means trillion cubic feet.

"2-D Seismic" means an advanced technology method by which a cross-section of the earth's subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

"3-D Seismic" means an advanced technology method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, development and production.

"Working Interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties.

"Workover" means operations on a producing well to restore or increase production.

Item 1A. Risk Factors

Risks related directly to our Company

One should carefully consider the following risk factors, in addition to the other information set forth in this Report, before investing in shares of our common stock. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock. Some information in this Report may contain "forward-looking" statements that discuss future expectations of our financial condition and results of operation. The risk factors noted in this section and other factors could cause our actual results to differ materially from those contained in any forward-looking statements.

The current global economic and financial environment could lead to an extended national or global economic recession. A slowdown in economic activity caused by a recession would likely reduce national and worldwide demand for oil and natural gas and result in lower commodity prices for long periods of time. Costs of exploration, development and production have not yet adjusted to current economic conditions. or in proportion to the significant reduction in product prices. Prolonged, substantial decreases in oil and natural gas prices would likely have a material adverse effect on Spindletop’s business, financial condition and results of operations, could further limit the Company's access to liquidity and credit and could hinder its ability to satisfy its capital requirements.

Capital and credit markets have experienced unprecedented volatility and disruption during recent years. Given the current levels of market volatility and disruption, the availability of funds from those markets has diminished substantially. Further, arising from concerns about the stability of financial markets generally and the solvency of borrowers specifically, the cost of accessing the credit markets has increased as many lenders have raised interest rates, enacted tighter lending standards or altogether ceased to provide funding to borrowers.

Due to these capital and credit market conditions, Spindletop cannot be certain that funding will be available to the Company in amounts or on terms acceptable to the Company. The Company is evaluating whether current cash balances and cash flow from operations alone would be sufficient to provide working capital to fully fund the Company's operations. Accordingly, the Company is evaluating alternatives, such as joint ventures with third parties, or sales of interest in one or more of its properties. Such transactions if undertaken, could result in a reduction in the Company's operating interests or require the Company to relinquish the right to operate the property. There can be no assurance that any such transactions can be completed or that such transactions will satisfy the Company's operating capital requirements. If the Company is not successful in obtaining sufficient funding or completing an alternative transaction on a timely basis on terms acceptable to the Company, Spindletop would be required to curtail its expenditures or restructure its operations, and the Company would be unable to continue its exploration, drilling, and recompletion program, any of which would have a material adverse effect on Spindletop's business, financial condition and results of operations.

We face significant competition, and many of our competitors have resources in excess of our available resources.

The oil and gas industry is highly competitive. We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of producing properties and sale of crude oil and natural gas. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies with substantially larger operating staffs and greater capital resources than us. Such companies may be able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Exploratory drilling is a speculative activity that may not result in commercially productive reserves and may require expenditures in excess of budgeted amounts.

Drilling activities are subject to many risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, many of which are beyond our control, including economic conditions, mechanical problems, pressure or irregularities in formations, title problems, weather conditions, compliance with governmental requirements and shortages in or delays in the delivery of equipment and services. In today's environment, shortages make drilling rigs, labor and services difficult to obtain and could cause delays or inability to proceed with our drilling and development plans. Such equipment shortages and delays sometimes involve drilling rigs where inclement weather prohibits the movement of land rigs causing a high demand for rigs by a large number of companies during a relatively short period of time. Our future drilling activities may not be successful. Lack of drilling success could have a material adverse effect on our financial condition and results of operations.

Our operations are also subject to all the hazards and risks normally incident to the development, exploitation, production and transportation of, and the exploration for, oil and gas, including unusual or unexpected geologic formations, pressures, down hole fires, mechanical failures, blowouts, explosions, uncontrollable flows of oil, gas or well fluids and pollution and other environmental risks. These hazards could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. We participate in insurance coverage maintained by the operator of its wells, although there can be no assurances that such coverage will be sufficient to prevent a material adverse effect to us in such events.

The vast majority of our oil and gas reserves are classified as proved reserves. Recovery of the Company's future proved undeveloped reserves will require significant capital expenditures. Our management estimates that aggregate capital expenditures of approximately $ 108,000 will be required to fully develop some of these reserves in the next twelve month period. No assurance can be given that our estimates of capital expenditures will prove accurate, that our financing sources will be sufficient to fully fund our planned development activities or that development activities will be either successful or in accordance with our schedule. Additionally, any significant decrease in oil and gas prices or any significant increase in the cost of development could result in a significant reduction in the number of wells drilled and/or reworked. No assurance can be given that any wells will produce oil or gas in commercially profitable quantities.

We are subject to uncertainties in reserve estimates and future net cash flows.

This annual report contains estimates of our oil and gas reserves and the future net cash flows from those reserves. These estimates have been prepared by Company personnel for 2012, 2011 and 2010. There are numerous uncertainties inherent in estimating quantities of reserves of oil and gas and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control. The reserve estimates in this annual report are based on various assumptions, including, for example, constant oil and gas prices, operating expenses, capital expenditures and the availability of funds, and therefore, are inherently imprecise indications of future net cash flows. Actual future production, cash flows, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves set forth in this prospectus. Additionally, our reserves may be subject to downward or upward revision based upon actual production performance, results of future development and exploration, prevailing oil and gas prices and other factors, many of which are beyond our control.

The present value of future net reserves discounted at 10% (the "PV-10") of proved reserves referred to in this annual report should not be construed as the current market value of the estimated proved reserves of oil and gas attributable to our properties. In accordance with applicable requirements of the SEC, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate, whereas actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by: (i) the timing of both production and related expenses; (ii) changes in consumption levels; and (iii) governmental regulations or taxation. In addition, the calculation of the present value of the future net cash flows using a 10% discount as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and gas industry in general. Furthermore, our reserves may be subject to downward or upward revision based upon actual production, results of future development, supply and demand for oil and gas, prevailing oil and gas prices and other factors. See "Properties - Oil and Gas Reserves."

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

There are risks in acquiring producing oil and gas properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, increasing the scope, geographic diversity and complexity of our operations.

One of our business strategies includes growing our reserve base through acquisitions. Our failure to integrate acquired properties successfully into our existing business, or the expense incurred in consummating future acquisitions, could result in unanticipated expenses and losses. In addition, we may assume cleanup or reclamation obligations or other unanticipated liabilities in connection with these acquisitions. The scope and cost of these obligations may ultimately be materially greater than estimated at the time of the acquisition.

We are continually investigating opportunities for acquisitions. In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Our ability to make future acquisitions may be constrained by our ability to obtain additional financing.

Possible future acquisitions could result in our incurring debt, contingent liabilities and expense, all of which could have a material effect on our financial condition and operating results.

Acquisitions may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, recovery applicability from waterflood and Enhanced Oil Recovery techniques (“EOR”), future oil and natural gas prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well or property. Even when we inspect a well or property, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. It is our current intention to continue focusing on acquiring properties with development and exploration potential located in onshore United States. To the extent that we acquire properties substantially different from the properties in our primary operating regions or acquire properties that require different technical expertise, we may not be able to realize the economic benefits of these acquisitions as efficiently as in our prior acquisitions.

We cannot control activities on properties we do not operate. Failure to fund capital expenditure requirements may result in reduction or forfeiture of our interests in some of our non-operated projects.

We do not operate some of the properties in which we have an interest and we have limited ability to exercise influence over operations for these properties or their associated costs. As of December 31, 2012, approximately 19% of our crude oil and natural gas proved reserves were operated by other companies. Our dependence on other operators and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted return on capital in drilling or acquisition activities and our targeted production growth rate. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control, including the operator’s expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

When we are not the majority owner or operator of a particular crude oil or natural gas project, we may have no control over the timing or amount of capital expenditures associated with such project. If we are not willing or able to fund our capital expenditures relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

We are subject to risks associated with the current United States Government Administration’s proposed budget features.

The Obama administration has set forth budget proposals which if passed, would significantly curtail our ability to attract investors and raise capital. Proposed changes in the Federal income tax laws which would eliminate or reduce the percentage depletion deduction and the deduction for intangible drilling and development costs for small independent producers, will significantly reduce the investment capital available to those in the industry as well as our Company. Lengthening the time to expense seismic costs will also have an adverse effect on our ability to explore and find new reserves.

We are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

Our oil and gas business involves a variety of operating risks, including, but not limited to, unexpected formations or pressures, uncontrollable flows of oil, gas, brine or well fluids into the environment (including groundwater contamination), blowouts, fires, explosions, pollution and other risks, any of which could result in personal injuries, loss of life, damage to properties and substantial losses. Although we carry insurance at levels that we believe are reasonable, we are not fully insured against all risks. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on our financial condition and operations.

From time to time, due primarily to contract terms, pipeline interruptions or weather conditions, the producing wells in which we own an interest have been subject to production curtailments. The curtailments range from production being partially restricted to wells being completely shut-in. The duration of curtailments varies from a few days to several months. In most cases, we are provided only limited notice as to when production will be curtailed and the duration of such curtailments. We are not currently experiencing any material curtailment of our production.

We intend to increase to some extent our development and, to a lesser extent, exploration activities. Exploration drilling and, to a lesser extent, development drilling of oil and gas reserves involve a high degree of risk that no commercial production will be obtained and/or that production will be insufficient to recover drilling and completion costs. The cost of drilling, completing and operating wells is often uncertain. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery of equipment. Furthermore, completion of a well does not assure a profit on the investment or a recovery of drilling, completion and operating costs.

We depend on our key management personnel and technical experts and the loss of any of these individuals could adversely affect our business.

If we lose the services of our key management personnel, technical experts or are unable to attract additional qualified personnel, our business, financial condition, results of operations, development efforts and ability to grow could suffer. We have assembled a team of engineers and geologists who have considerable experience in applying advanced drilling and completion techniques to explore for and to develop crude oil and natural gas. We depend upon the knowledge, skill and experience of these experts to assist us in improving the performance and reducing the risks associated with our participation in crude oil and natural gas exploration and development projects. In addition, the success of our business depends, to a significant extent, upon the abilities and continued efforts of our management, particularly Chris Mazzini, our Chief Executive Officer, President and Chairman of the Board. We do not have an employment agreement with or key-man life insurance on Mr. Mazzini or any of our other employees.

Certain of our affiliates control a majority of our outstanding common stock, which may affect your vote as a shareholder.

Our executive officers, directors and their affiliates hold approximately 85% of our outstanding shares of common stock. As a result, officers, directors and their affiliates and such shareholders have the ability to exert significant influence over our business affairs, including the ability to control the election of directors and results of voting on all matters requiring shareholder approval. This concentration of voting power may delay or prevent a potential change in control.

Certain of our affiliates have engaged in business transactions with the Company, which may result in conflicts of interest.

Certain officers, directors and related parties, including entities controlled by Mr. Mazzini, the President and Chief Executive Officer, have engaged in business transactions with the Company which were not the result of arm's length negotiations between independent parties. Our management believes that the terms of these transactions were as favorable to us as those that could have been obtained from unaffiliated parties under similar circumstances. All future transactions between us and our affiliates will be on terms no less favorable than could be obtained from unaffiliated third parties and will be approved by a majority of the disinterested members of our Board of Directors.

Our common stock is traded on the Over-the-Counter market and is currently quoted on the OTC Bulletin Board ("OTCQB"), symbol "SPND".

The liquidity of our common stock may be adversely affected, and purchasers of our common stock may have difficulty selling our common stock, if our common stock does not continue to trade in that or another suitable trading market.

There is presently only a limited public market for our common stock, and there is no assurance that a ready public market for our securities will develop. It is likely that any market that develops for our common stock will be highly volatile and that the trading volume in such market will be limited. The trading price of our common stock could be subject to wide fluctuations in response to quarter-to-quarter variations in our operating results, announcements of our drilling results and other events or factors. In addition, the United States stock market has from time to time experienced extreme price and volume fluctuations that have affected the market price for many companies and which often have been unrelated to the operating performance of these companies. These broad market fluctuations may adversely affect the market price of our securities.

We do not intend to declare dividends in the foreseeable future.

Our Board of Directors presently intends to retain all of our earnings for the expansion of our business. We therefore do not anticipate the distribution of cash dividends in the foreseeable future. Any future decision of our Board of Directors to pay cash dividends will depend, among other factors, upon our earnings, financial position and cash requirements.

We are subject to certain title risks.

Our company employees and contract land professionals have reviewed title records or other title review materials relating to substantially all of our producing properties. The title investigation performed by us prior to acquiring undeveloped properties is thorough, but less rigorous than that conducted prior to drilling, consistent with industry standards. We believe we have satisfactory title to all our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. At December 31, 2012, our leaseholds for some of our net acreage were being kept in force by virtue of production on that acreage in paying quantities. The remaining net acreage was held by lease rentals and similar provisions and requires production in paying quantities prior to expiration of various time periods to avoid lease termination.

We expect to make acquisitions of oil and gas properties from time to time subject to available resources. In making an acquisition, we generally focus most of our title and valuation efforts on the more significant properties. It is generally not feasible for us to review in-depth every property we purchase and all records with respect to such properties. However, even an in-depth review of properties and records may not necessarily reveal existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their deficiencies and capabilities. Evaluation of future recoverable reserves of oil and gas, which is an integral part of the property selection process, is a process that depends upon evaluation of existing geological, engineering and production data, some or all of which may prove to be unreliable or not indicative of future performance. To the extent the seller does not operate the properties, obtaining access to properties and records may be more difficult. Even when problems are identified, the seller may not be willing or financially able to give contractual protection against such problems, and we may decide to assume environmental and other liabilities in connection with acquired properties.

Our business is highly capital-intensive requiring continuous development and acquisition of oil and gas reserves. In addition, capital is required to operate and expand our oil and gas field operations and purchase equipment. At December 31, 2012, we had working capital of $5,939,000. We anticipate that we will be able to meet our cash requirements for the next 12 months. However, if such plans or assumptions change or prove to be inaccurate, we could be required to seek additional financing sooner than currently anticipated.

We have funded our operations, acquisitions and expansion costs primarily through our internally generated cash flow. Our success in obtaining the necessary capital resources to fund future costs associated with our operations and expansion plans is dependent upon our ability to: (i) increase revenues through acquisitions and recovery of our proved producing and proved developed non-producing oil and gas reserves; and (ii) maintain effective cost controls at the corporate administrative office and in field operations. However, even if we achieve some success with our plans, there can be no assurance that we will be able to generate sufficient revenues to achieve significant profitable operations or fund our expansion plans.

We have substantial capital requirements necessary for undeveloped properties for which we may not be able to obtain adequate financing.

Development of our properties will require additional capital resources. We have no commitments to obtain any additional debt or equity financing and there can be no assurance that additional financing will be available, when required, on favorable terms to us. The inability to obtain additional financing could have a material adverse effect on us, including requiring us to curtail significantly our oil and gas acquisition and development plans or farm-out development of our properties. Any additional financing may involve substantial dilution to the interests of our shareholders at that time.

Oil and natural gas prices fluctuate widely and low prices could have a material adverse impact on our business and financial results.

Our revenues, profitability and the carrying value of our oil and gas properties are substantially dependent upon prevailing prices of, and demand for, oil and gas and the costs of acquiring, finding, developing and producing reserves. Our ability to obtain borrowing capacity, to repay future indebtedness, and to obtain additional capital on favorable terms is also substantially dependent upon oil and gas prices. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. Prices for oil and gas are subject to wide fluctuations in response to: (i) relatively minor changes in the supply of, and demand for, oil and gas; (ii) market uncertainty; and (iii) a variety of additional factors, all of which are beyond our control. These factors include domestic and foreign political conditions, the price and availability of domestic and imported oil and gas, the level of consumer and industrial demand, weather, domestic and foreign government relations, the price and availability of alternative fuels and overall economic conditions. Furthermore, the marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Volatility in oil and gas prices could affect our ability to market our production through such systems, pipelines or facilities. As of December 31, 2012, approximately 87% of our oil and gas production is currently sold to 17 purchasing firms on a month-to-month basis at prevailing spot market prices. Oil prices remained subject to unpredictable political and economic forces during 2012, 2011, and 2010, and experienced fluctuations similar to those seen in natural gas prices for the year. We believe that oil prices will continue to fluctuate in response to changes in the policies of the Organization of Petroleum Exporting Countries ("OPEC"), changes in demand from many Asian countries, current events in the Middle East, security threats to the United States, and other factors associated with the world political and economic environment. As a result of the many uncertainties associated with levels of production maintained by OPEC and other oil producing countries, the availabilities of worldwide energy supplies and competitive relationships and consumer perceptions of various energy sources, we are unable to predict what changes will occur in crude oil and natural gas prices.

We may be responsible for additional costs in connection with abandonment of properties.

We are responsible for payment of plugging and abandonment costs on its oil and gas properties pro rata to our working interest. Based on our experience, we anticipate that in most cases, the ultimate aggregate salvage value of lease and well equipment located on our properties should equal to the costs of abandoning such properties. There can be no assurance, however, that we will be successful in avoiding additional expenses in connection with the abandonment of any of our properties. In addition, abandonment costs and their timing may change due to many factors, including actual production results, inflation rates and changes in environmental laws and regulations.

Risks that Involve the Oil & Gas Industry in General.

We are subject to various governmental regulations which may cause us to incur substantial costs.

Our operations are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production related operations are or have been subject to price controls, taxes and other laws and regulations relating to the oil and gas industry. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry increases our cost of doing business and affects our profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, because such laws and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws and regulations.

Sales of natural gas by us are not regulated and are generally made at market prices. However, the Federal Energy Regulatory Commission ("FERC") regulates interstate natural gas transportation rates and service conditions, which affect the marketing of natural gas produced by us, as well as the revenues received by us for sales of such production. Sales of our natural gas currently are made at uncontrolled market prices, subject to applicable contract provisions and price fluctuations that normally attend sales of commodity products.

Since the mid-1980s, the FERC has issued a series of orders, culminating in Order Nos. 636, 636-A and 636-B ("Order 636"), that have significantly altered the marketing and transportation of natural gas. Order 636 mandated a fundamental restructuring of interstate pipeline sales and transportation service, including the unbundling by interstate pipelines of the sale, transportation, storage and other components of the city-gate sales services such pipelines previously performed. One of the FERC's purposes in issuing the orders was to increase competition within all phases of the natural gas industry. Order 636 and subsequent FERC orders issued in individual pipeline restructuring proceedings have been the subject of appeals, and the courts have largely upheld Order 636. Because further review of certain of these orders is still possible, and other appeals may be pending, it is difficult to exactly predict the ultimate impact of the orders on us and our natural gas marketing efforts. Generally, Order 636 has eliminated or substantially reduced the interstate pipelines' traditional role as wholesalers of natural gas, and has substantially increased competition and volatility in natural gas markets.

While significant regulatory uncertainty remains, Order 636 may ultimately enhance our ability to market and transport our natural gas, although it may also subject us to greater competition, more restrictive pipeline imbalance tolerances and greater associated penalties for violation of such tolerances.

The FERC has announced several important transportation-related policy statements and proposed rule changes, including the appropriate manner in which interstate pipelines release capacity under Order 636 and, more recently, the price which shippers can charge for their released capacity. In addition, in 1995, the FERC issued a policy statement on how interstate natural gas pipelines can recover the costs of new pipeline facilities. In January 1997, the FERC issued a policy statement and a request for comments concerning alternatives to its traditional cost-of-service rate making methodology. A number of pipelines have obtained FERC authorization to charge negotiated rates as one such alternative. While any additional FERC action on these matters would affect us only indirectly, these policy statements and proposed rule changes are intended to further enhance competition in natural gas markets. We cannot predict what the FERC will take on these matters, nor can we predict whether the FERC's actions will achieve its stated goal of increasing competition in natural gas markets. However, we do not believe that we will be treated materially differently than other natural gas producers and marketers with which we compete.

The price we receive from the sale of oil is affected by the cost of transporting such products to market. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system for transportation rates for oil pipelines, which, generally, would index such rates to inflation, subject to certain conditions and limitations. These regulations could increase the cost of transporting oil by interstate pipelines, although the most recent adjustment generally decreased rates. These regulations have generally been approved on judicial review. We are not able to predict with certainty the effect, if any, of these regulations on its operations. However, the regulations may increase transportation costs or reduce wellhead prices for oil.

The State of Texas and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration for and production of oil and gas. Such states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of such wells. The statutes and regulations of certain states limit the rate at which oil and gas can be produced from our properties. However, we do not believe we will be affected materially differently by these statutes and regulations than any other similarly situated oil and gas company.

We may not have enough insurance to cover all of the risks we face, which could result in significant financial exposure.

We maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. We may elect not to carry insurance if our management believes that the cost of insurance is excessive relative to the risks presented. If an event occurs that is not covered, or not fully covered, by insurance, it could harm our financial condition, results of operations and cash flows. In addition, we cannot fully insure against pollution and environmental risks.

We are subject to various environmental risks which may cause us to incur substantial costs.

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling and transportation of oil and gas and the discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations, and violations are subject to fines, penalties or injunctions. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us. The impact of such changes, however, would not likely be any more burdensome to us than to any other similarly situated oil and gas company.

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liabilities for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources. Furthermore, neighboring landowners and other third parties may file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We generate typical oil and gas field wastes, including hazardous wastes that are subject to the Federal Resources Conservation and Recovery Act and comparable state statutes. The United States Environmental Protection Agency and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our oil and gas operations that are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes", and therefore be subject to more rigorous and costly operating and disposal requirements.

The Oil Pollution Act ("OPA") imposes a variety of requirements on responsible parties for onshore and offshore oil and gas facilities and vessels related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The "responsible party" includes the owner or operator of an onshore facility or vessel or the lessee or permittee of, or the holder of a right of use and easement for, the area where an onshore facility is located. OPA assigns liability to each responsible party for oil spill removal costs and a variety of public and private damages from oil spills. Few defenses exist to the liability for oil spills imposed by OPA. OPA also imposes financial responsibility requirements. Failure to comply with ongoing requirements or inadequate cooperation in a spill event may subject a responsible party to civil or criminal enforcement actions.

We own or lease properties that for many years have produced oil and gas. We also own natural gas gathering systems. It is not uncommon for such properties to be contaminated with hydrocarbons. Although we or previous owners of these interests may have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties or on or under other locations where such wastes have been taken for disposal. These properties may be subject to federal or state requirements that could require us to remove any such wastes or to remediate the resulting contamination. In addition to properties that we operate, we have interests in many properties which are operated by third parties over whom we have limited control. Notwithstanding our lack of control over properties operated by others, the failure of the previous owners or operators to comply with applicable environmental regulations may, in certain circumstances, adversely impact us.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

OIL AND GAS PROPERTIES

The following table sets forth pertinent data with respect to the Company-owned oil and gas properties, all located within the continental United States, as estimated by the Company:

	Years Ended December 31,		
	2012	2011	2010
Gas and Oil Properties, net (1)			
Proved developed gas reserves-Mcf (2)			
Proved developed producing	6,506,000	8,124,000	8,106,000
Proved developed non-producing	27,000	27,000	648,000
Proved undeveloped gas reserves-Mcf (3)	—	—	1,868,000
Total proved gas reserves-Mcf	6,533,000	8,151,000	10,622,000
Proved Developed Crude Oil and			
Condensate reserves-Bbls (2)			
Proved developed producing	468,000	401,000	328,000
Proved developed non-producing	31,000	31,000	34,000
Proved Undeveloped crude oil and			
Condensate reserves-Bbls (3)	—	—	—
	499,000	432,000	362,000

(1) The estimate of the net proved oil and gas reserves, future net revenues, and the present value of future net revenues.

(2) "Proved Developed Oil and Gas Reserves" are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

(3) "Proved Undeveloped Reserves" are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See Footnote 18 to the Financial Statements, Supplemental Reserve Information (Unaudited), for further explanation of the changes for 2010 through 2012.

(4) Reserve amounts are rounded to the nearest thousand.

Productive Wells

The following table sets forth our domestic productive wells and includes both operated wells and wells operated by third parties at December 31, 2012.

Gas Wells		Oil Wells		Total Wells	
Gross	Net	Gross	Net	Gross	Net
356	98.56	173	64.14	529	162.70

Acreage

The following table sets forth our undeveloped and developed gross and net leasehold acreage for our operated and non-operated wells at December 31, 2012. Undeveloped acreage includes leased acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves. Undeveloped acreage should not be confused with undrilled acreage held by Production under the terms of a lease. Undrilled acreage held by production under the terms of a lease is included in the Developed Acreage category total shown below.

Undeveloped Acreage		Developed Acreage		Total Acreage	
Gross	Net	Gross	Net	Gross	Net
4,960	1,554	96,925	21,728	101,885	23,282

All the leases for the undeveloped acreage summarized in the preceding table will expire at the end of their respective primary terms unless prior to that date, the existing leases are renewed or production has been obtained from the acreage subject to the lease, in which event the lease will remain in effect until the cessation of production. As is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except as to claims made by, through or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defect or from defects in the assignment of leasehold rights.

Wells Drilled and Completed

The Company's working interests in both operated and outside operated exploration and development wells completed during the years indicated were as follows:

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells (1):						
Productive	—	—	—	—	—	—
Non-Productive	—	—	—	—	—	—
Total	—	—	—	—	—	—
Developed Wells (2):						
Productive	9.000	1.321	11.000	1.036	10.000	1.391
Non-Productive	—	—	—	—	—	—
Total	9.000	1.321	11.000	1.036	10.000	1.391
Total Exploration & Development Wells:						
Productive	9.000	1.321	11.000	1.036	10.000	1.391
Non-Productive	—	—	—	—	—	—
Total	9.000	1.321	11.000	1.036	10.000	1.391

(1) An exploratory well is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

(2) A development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

The following tables set forth additional data with respect to production from Company-owned oil and gas operated and non-operated properties, all located within the continental United States:

	For the years ended December 31,				
	2012	2011	2010	2009	2008
Oil and Gas Production, net:					
Natural Gas (Mcf)	791,708	733,816	823,957	866,416	1,231,835
Crude Oil & Condensate (Bbl)	79,514	48,708	31,526	25,875	32,663
Average Sales Price per Unit Produced					
Natural Gas (Mcf)	$ 3.64	$ 5.34	$ 4.89	$ 4.13	$ 8.41
Crude Oil & Condensate (Bbl)	$ 89.50	$ 83.85	$ 74.35	$ 56.55	$ 71.21
Average Production Cost per Equivalent Barrel (1) (2)	$ 16.65	$ 19.02	$ 15.48	$ 14.37	$ 14.98

(1) Includes severance taxes and ad valorem taxes.

(2) Gas production is converted to equivalent barrels at the rate of six MCFG per barrel, representing relative energy content of natural gas to oil.

The Company owns producing royalties and overriding royalties under properties located in Texas. The revenue from these properties is not significant.

The Company is not aware of any major discovery or other favorable or adverse event that is believed to have caused a significant change in the estimated proved reserves since December 31, 2011.

OFFICE SPACE

The Company owns a commercial office building. The property is a two story multi-tenant, garden office building with a sub-grade parking garage. The 31 year old building contains approximately 46,286 rentable square feet and sits on a 1.4919 acre block of land situated in north Dallas, Texas in close proximity to hotels, restaurants and shopping areas (the Galleria Mall) with easy access to Interstate Highway 635 (LBJ Freeway) and Dallas Parkway (North Dallas Toll Road). The Company occupies approximately 12,759 rentable square feet of the building as its primary office headquarters, and leases the remaining space in the building to non-related third party commercial tenants at prevailing market rates.

The address of the Company's principal executive offices is One Spindletop Centre, 12850 Spurling Road, Suite 200, Dallas, Texas 75230. The telephone number is (972) 644-2581.

PIPELINES

The Company owns, through its subsidiary, PPC, 26.1 miles of natural gas pipelines in Parker, Palo Pinto and Eastland Counties, Texas. These pipelines are steel and polyethylene and range in size from two inches to four inches. These pipelines primarily gather natural gas from wells operated by the Company and in which the Company owns a working interest, but also for other parties.

The Company normally does not purchase and resell natural gas, but gathers gas for a fee. The fees charged in some cases are subject to regulations by the State of Texas and the Federal Energy Regulatory Commission. Average daily volumes of gas gathered by the pipelines owned by the Company were 1,345, 1,604, and 1,793, mcfgpd for 2012, 2011, and 2010, respectively.

Oilfield Production Equipment

The Company owns various natural gas compressors, pumping units, dehydrators and various other pieces of oil field production equipment.

Substantially all of the equipment is located on oil and gas properties operated by the Company and in which it owns a working interest. The rental fees are charged as lease operating fees to each property and each owner.

M-R Oilfield Services, LP, is an oilfield service company which provides roustabout, swabbing and completion services to the Company at rates which are at or below market. This limited partnership has Chris G. Mazzini and Michelle H. Mazzini as its limited partners. This oilfield services company currently does work exclusively for the Company and its related company, Giant Energy, although it has contemplated doing work for unrelated third parties as well. The Company benefits by having immediate access to services.

Item 3. Legal Proceedings

Neither the Registrant nor its subsidiaries nor any officers or directors is a party to any material pending legal proceedings for or against the Company or its subsidiary nor are any of their properties subject to any proceedings.

During the fourth quarter of the fiscal year covered by this report, no proceeding previously reported was terminated.

Item 4. Mine Safety Disclosures

Not Applicable

PART II

Item 5. Market For The Company's Common Stock, Related Stockholder Matters And Issuer Purchases Of Equity Securities.

The Company's common stock trades over-the-counter under the symbol "SPND".

Prior to 2004, no significant public trading market had been established for the Company's common stock. The Company does not believe that listings of bid and asking prices for its stock are indicative of the actual trades of its stock, since trades are made infrequently. The following table shows high and low trading prices for each quarter in 2012, 2011, and 2010.

	Price Per Share	
	High	Low
2012		
First Quarter	$1.90	$1.50
Second Quarter	2.35	1.84
Third Quarter	2.09	1.91
Fourth Quarter	3.10	1.86
2011		
First Quarter	2.79	2.79
Second Quarter	2.52	1.52
Third Quarter	2.00	1.70
Fourth Quarter	2.10	1.70
2010		
First Quarter	1.99	1.65
Second Quarter	5.50	1.60
Third Quarter	2.25	1.39
Fourth Quarter	2.25	1.45

During the First Quarter of 2013, subsequent to year end, the following high and low prices were recorded for the Company's common stock

	Price Per Share	
	High	Low
2013		
First Quarter	$2.60	$2.08

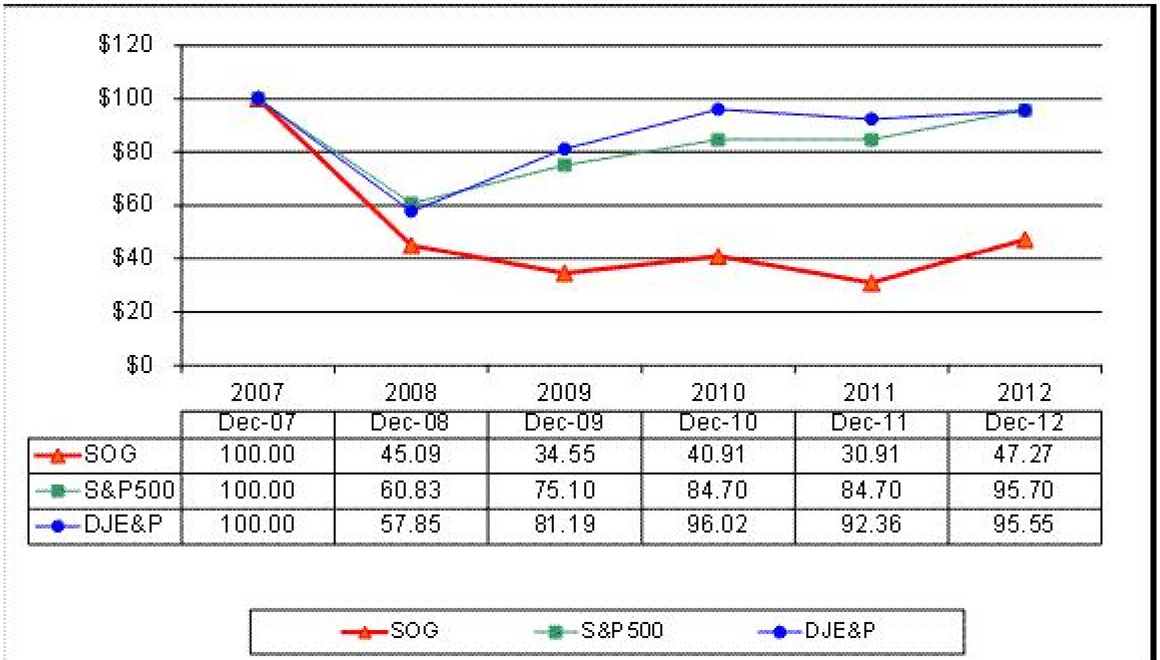
There is no amount of common stock that is subject to outstanding warrants to purchase, or securities convertible into, common stock of the Company.

According to the transfer records of the Company at April 1, 2013, common stock of the Company was held by approximately 545 known holders of record.

The following chart compares the yearly percentage change in the cumulative total stockholder return on the Company's Common Stock during the five years ended December 31, 2012 with the cumulative total return of the Standard and Poor's 500 Stock Index and of the Dow Jones U.S. Exploration and Production Index (formerly Dow Jones Secondary Oil Stock Index). The comparison assumes $100 was invested on December 31, 2007 in the Company's Common Stock and in each of the foregoing indices and assumes reinvestment of dividends. The Company paid no dividends on its Common Stock during the five-year period.

Stock Performance Chart

Comparison of Five-Year Cumulative Total Return Among
Spindletop Oil & Gas Co., S&P 500 Index and
the Dow Jones U.S. Exploration and Production Index



	Dec-07	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12
SOG	100.00	45.09	34.55	40.91	30.91	47.27
S&P500	100.00	60.83	75.10	84.70	84.70	95.70
DJE&P	100.00	57.85	81.19	96.02	92.36	95.55

The Company has not paid any dividends since its reorganization and it is not contemplated that it will pay any dividends on its Common Stock in the foreseeable future. The Business Loan Agreement entered into between the Company and JPMorgan Chase Bank for the purpose of acquiring its commercial office building contains restrictions on the payment of dividends in the event a default under terms of the Business Loan Agreement has occurred and is continuing or would result from the payment of such dividends or distributions.

The Registrant currently serves as its own stock transfer agent and registrar.

The Company has not approved nor authorized any standing repurchase program for its common stock.

During the fourth quarter of the fiscal year ended December 31, 2012, the Company made the following repurchases of its common stock:

> Effective October 30, 2012, the Company repurchased 700,000 shares of its common stock for a purchase price of $1,491,000 or $2.13 per share.
>
> On December 18, 2012, the Company repurchased 24,534 shares of its common stock for a purchase price of $36,801 or $1.50 per share.

The repurchased shares are held as Treasury Stock.

Item 6. Selected Financial Data

The selected financial information presented should be read in conjunction with the consolidated financial statements and the related notes thereto.

	For the years ended December 31,				
	2012	2011	2010	2009	2008
Total Revenue	$12,106,000	$ 9,340,000	$ 7,656,000	$ 6,913,000	$14,064,000
Net Income	3,659,000	1,753,000	447,000	39,000	3,521,000
Earnings per Share	$ 0.49	$ 0.23	$ 0.06	$ 0.01	$ 0.46

	For the years ended December 31,				
	2012	2011	2010	2009	2008
Total Assets	$24,653,000	$23,279,000	$20,777,000	$20,386,000	$21,289,000
Long-Term Debt	600,000	720,000	840,000	960,000	1,080,000

Item 7. Management's Discussion And Analysis Of Financial Condition And Results Of Operations

Liquidity and Capital Resources

The Company's operating capital needs, as well as its capital spending program are generally funded from cash flow generated by operations. Because future cash flow is subject to a number of variables, such as the level of production and the sales price of oil and natural gas, the Company can provide no assurance that its operations will provide cash sufficient to maintain current levels of capital spending. Accordingly, the Company may be required to seek additional financing from third parties in order to fund its exploration and development programs.

Results of Operations

2012 Compared to 2011

Oil revenue for 2012 was approximately $7,116,000 compared to $4,084,000 for 2011, an increase of approximately $3,032,000 or 74%. Oil prices increased to an average of $89.49 per barrel in 2012 from an average of $83.85 per bbl in 2011, an increase of $5.63 per bbl or 7%. In addition to the increase in prices, oil sales increased to 79,514 bbls from approximately 48,708 bbls in 2011, an increase of 30,814 bbls or 63%. The increase in oil revenue and sales is predominantly due to participation in new wells during the last half 2012.

Gas revenue for 2012 was approximately $2,882,000 compared to $3,916,000 for 2011, a decrease of approximately $1,034,000 or 26%. Gas sales increased to approximately 792,000 mcf in 2012 from approximately 734,000 mcf in 2011, an increase of 58,000 mcf or 8%. The net increase in natural gas sales was due to the participation in, and the acquisition of new wells. Gas prices, however, decreased to an average of $3.64 per mcf in 2012, a decrease of $1.70 or 32% from an average of $5.34 per mcf in 2011.

Revenue from lease operations was $359,000 for 2012, an increase of $70,000 or 24% from $289,000 in 2011. This was due primarily to an increase in field supervision charges on operated wells of approximately $44,000 as a result of workover activity during 2012. In addition there was an increase in administrative overhead billed to working interest owners of approximately $26,000 due primarily to an increase in COPAS overhead rates billed

Revenue from gas gathering for 2012 was $145,000, a decrease of $27,000 or 16% from $172,000 in 2011. This was due primarily to a decrease in natural gas volume sold through Prairie Pipeline.

Real estate income for 2012 was $242,000, down 44% or $194,000 from $436,000 in 2011. This was due primarily to the expiration of a large lease contract in late 2011 which was not renewed and some lease renewal incentives.

Interest income for 2012 was approximately $78,000, a decrease of approximately $5,000 from approximately $83,000 in 2011 or 6%. Overall interest rates on deposit accounts at most of the banks in which the Company is a depositor, have decreased over prior years.

Other income for 2012 was $1,284,000, as compared to $360,000 in 2011, an increase of $924,000 or 257%. This change is due to the increase in cash received for farm-out agreements in 2012 over that received during 2011. From time to time, the Company farms out some of its leasehold acreage to non-affiliated third parties for exploration and development drilling. Generally, the Company receives a one-time payment for the agreement. The revenues from these farm-out agreements vary in size and frequency and should not be considered as regularly recurring revenues that the Company receives.

Lease operations expense for 2012 was $2,631,000 as compared to $2,444,000 in 2011, a net increase of approximately $187,000, or 8%. Of this net increase, approximately $112,000 is due to increased workover activity, approximately $78,000 is due to new properties added since 2011, and a reduction of approximately $31,000 is due to a decrease in expenses from non-operated properties. The remaining $28,000 represents net increases and decreases on various properties due to general price increases and changes in levels of workover activity. These increases were offset by a one-time payment covering expenses from 2002 to 2011 associated with the acquisition of the working interest in the Davis Heirs #1 well during the first quarter of 2011.

Production taxes, gathering, transportation and marketing expenses for 2012 were approximately $891,000 compared to $809,000 in 2011, a net increase of $82,000. This 10% net increase is the result of an increase in severance taxes based on the increase in oil revenues. This increase was offset by an overall decrease in severance taxes based on decreased gas revenues and severance tax exemptions on certain of the Company's gas wells. Gathering and transportation charges increased due to a net increase in gas volumes sold during the period, which was offset by an overall decrease in marketing and other deductions.

Pipeline and rental operation expenses were approximately $26,000 in 2012 compared to approximately $25,000 in 2011, an increase of approximately $1,000 or 4%. This was due mainly to an increase in the costs associated with compressor and pipeline repairs.

Real estate operations expenses for 2012 were $185,000, down from $225,000 in 2011. This 18% decrease of $40,000 was primarily due to operating efficiencies, from the reduced usage of the building as the result of the expiration of the lease noted above.

Depreciation and amortization expense for 2012 was $1,647,000 compared to $1,152,000 for 2011, an increase of $495,000, or 43%. The Company re-evaluated its proved oil and gas reserves as of December 31, 2012, and decreased its estimated total proved reserves by approximately 203,000 BOE to 1,588,000 BOE at the end of 2012 compared to 1,791,000 BOE at the end of 2011, a decrease of approximately 11%. Sales of oil and gas products during 2012 increased by approximately 40,000 BOE from approximately 171,000 BOE in 2011 to approximately 211,000 BOE in 2012, an increase of approximately 23%. (See Footnote 18 to the Financial Statements). This resulted in an increase in the depletion rate factor from 8.718% in 2011 on an unamortized full cost pool base of $11,843,000 to a depletion rate factor of 11.754% on an unamortized full cost pool base of $13,464,000 in 2012. The net increase in the unamortized full cost pool base of $1,621,000 was due primarily to an increase in the amounts capitalized in the full cost pool of approximately $2,654,000 less the increase in accumulated depletion of $1,032,479.

Asset Retirement Obligation (“ARO”) accretion expense for 2012 was $40,000 up from $34,000 in 2011; an increase of $6,000 or 17%. The ARO calculation is based on the Company’s annual reserve report and takes into consideration the changes between years of the Company’s estimated obligation to plug its interest in existing wells. This estimated future cost is discounted using a 10% discount factor based on the estimated life of each property. Changes are incorporated as applicable into the full cost pool and the carrying value of the liability. Accretion expense measures and incorporates changes due to the passage of time into the carrying amount of the liability.

General and administrative expenses for 2012 were $3,719,000 compared to $3,275,000 for 2011, an increase of approximately $444,000 between years or 14%. This increase is due mainly to payroll and associated employee benefit costs during 2012.

Interest expense for 2012 was $29,000, down from $55,000 in 2011; a decrease of $26,000 or 47%. The reason for the reduction is the decreasing loan balance on which interest is paid, and that the interest rate on the loan was adjusted from 6.11% in December, 2011 to 3.61% for future years.

2011 Compared to 2010

Oil revenue for 2011 was approximately $4,084,000 compared to $2,368,000 for 2010, an increase of approximately $1,716,000 or 72%. Oil prices increased to an average of $83.85 per barrel in 2011 from an average of $74.35 per bbl in 2010, an increase of $9.50 per bbl or 13%. In addition to the increase in prices, oil sales increased to 48,708 bbls from approximately 31,526 bbls in 2010, an increase of 17,182 bbls or 55%. The increase in oil revenue and sales is predominantly due to properties acquired or drilled in 2011.

Gas revenue for 2011 was approximately $3,916,000 compared to $3,934,000 for 2010, a decrease of approximately $18,000 or 0.5%. Gas sales decreased to approximately 734,000 mcf in 2011 from approximately 824,000 mcf in 2010, a reduction of 90,000 mcf or 11%. Gas prices, however, increased to an average of $5.34 per mcf in 2011, an increase of $0.45 or 9% from an average of $4.89 per mcf in 2010.

Revenue from lease operations was $289,000 for 2011, a decrease of $30,000 or 9% from $319,000 in 2010. This decrease was a result of lower pumper fees and field supervision costs charged to operated properties between the two years.

Revenue from gas gathering for 2011 was $172,000, a decrease of $7,000 or 4% from $179,000 in 2010. This was due primarily to the decrease in gas volume sold.

Real estate income for 2011 was $436,000, down 3% or $12,000 from $448,000 in 2010. This was due primarily to the expiration of a rental contract in late 2011 which was not renewed and some lease renewal incentives.

Interest income for 2011 was $83,000, a decrease of $75,000 from $158,000 in 2010 or 47%. Overall interest rates on deposit accounts at most of the banks in which the Company is a depositor, have decreased significantly over prior years.

Other income for 2011 was $360,000, as compared to $250,000 in 2010, an increase of $110,000 or 44%. The increase is due primarily to increases in farmouts and assignment of certain leases between years. In addition, amounts were brought into income from reconciliation efforts on accounts payable for non-operated properties. Amounts carried as payables were determined not to be liabilities and were taken to income.

Lease operating expenses increased to $2,444,000 in 2011 from $1,901,000 in 2010 an increase of $543,000 or 29%. Approximately $525,000 of this net increase comes from operated wells drilled or acquired in 2011 or late 2010. Another $185,000 comes from an increase in non-operated wells, the majority of which is due to the acquisition of a non-operated working interest in the Davis Heirs #1 which included expenses from a time period of 2002 to 2011. Expenses to plug non-economical wells decreased by $157,000 from 2010 and the remaining difference was the result of a net difference in workover costs between the two years.

Production taxes, gathering, transportation and marketing expenses for 2011 were approximately $809,000 compared to $712,000 in 2010, a net increase of $97,000. This 14% net increase is due an increase of approximately $116,000 in Severance Taxes paid on properties acquired in 2011 or late 2010. This amount is offset by a reduction in other revenue deductions of approximately $20,000.

Pipeline and rental operation expenses were $25,000 in 2011 from $33,000 in 2010 a decrease of $8,000 or 24%. This was due mainly to a decrease in the costs associated with compressor and pipeline repairs.

Real estate operations expenses for 2011 were $225,000, down from $246,000 in 2010. This 9% decrease of $21,000 was mainly due to the reduction of electricity costs after the Company changed electric carriers.

Depreciation and amortization expense for 2011 was $1,152,000 compared to $1,042,000 for 2010, an increase of $110,000, or 11%. The Company re-evaluated its proved oil and gas reserves as of December 31, 2011, and decreased its estimated total proved reserves by approximately 342,000 BOE to 1,791,000 BOE at the end of 2011 compared to 2,133,000 BOE at the end of 2010, a decrease of approximately 16.0%. Sales of oil and gas products during 2011 increased by approximately 2,000 BOE from approximately 169,000 BOE in 2010 to approximately 171,000 BOE in 2011, an increase of approximately 1.2%. (See Footnote 18 to the Financial Statements). This resulted in an increase in the depletion rate factor from 7.336% in 2010 on an unamortized full cost pot base of $12,496,000 to a depletion rate factor of 8.718% on an unamortized full cost pot base of $11,843,000 in 2011. The decrease in the unamortized full cost pot base of $653,000 was due primarily to a reduction of future development costs as calculated in the Company’s reserve report between 2010 and 2011 of approximately $2,079,000.

Asset Retirement Obligation (“ARO”) accretion expense for 2011 was $34,000 down from $48,000 in 2010; a decrease of $14,000 or 29%. The ARO calculation is based on the Company’s annual reserve report and takes into consideration the changes between years of the Company’s estimated obligation to plug its interest in existing wells. This estimated future cost is discounted using a 10% discount factor based on the estimated life of each property. Changes are incorporated as applicable into the full cost pot and the carrying value of the liability. Accretion expense measures and incorporates changes due to the passage of time into the carrying amount of the liability.

General and administrative expenses for 2011 were $3,275,000 compared to $3,467,000 for 2010, a decrease of approximately $192,000 between years or 6%. This decrease is due mainly to the reduction in payroll and associated employee benefit costs during 2011.

Interest expense for 2011 was $55,000, down from $84,000 in 2010; a decrease of $29,000 or 35%. The majority of this change is due to a Revenue Agent’s Report assessed in late 2010 that was not incurred in 2011.

Certain Factors That Could Affect Future Operations

Certain information contained in this report, as well as written and oral statements made or incorporated by reference from time to time by the Company and its representatives in other reports, filings with the Securities and Exchange Commission, press releases, conferences, teleconferences or otherwise, may be deemed to be 'forward-looking statements' within the meaning of Section 21E of the Securities Exchange Act of 1934 and are subject to the 'Safe Harbor' provisions of that section.

Forward-looking statements include statements concerning the Company's and management's plans, objectives, goals, strategies and future operations and performance and the assumptions underlying such forward-looking statements. When used in this document, the words "anticipates", "estimates", "expects", "believes", "intends", "plans", and similar expressions are intended to identify such forward-looking statements. Actual results and developments could differ materially from those expressed in or implied by such statements due to these and other factor.

Item 8. Consolidated Financial Statements and Schedules Index at Page 46

Item 9. Changes In And Disagreements With Accountants On Accounting And Financial Disclosure

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial and Accounting Officer, we conducted an evaluation of the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e)) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), which are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Principal Executive Officer and Principal Financial and Accounting Officer, as appropriate to allow timely decisions regarding required disclosure. Based on this evaluation, our Principal Executive Officer and Principal Financial and Accounting Officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report.

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. There are inherent limitations to the effectiveness of any system of internal control over financial reporting. These limitations include the possibility of human error, the circumvention of overriding of the system and reasonable resource constraints. Because of its inherent limitations, our internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with policies or procedures may deteriorate.

Management assessed the effectiveness of the Company’s internal controls over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on management’s assessments and those criteria, management has concluded that Company’s internal control over financial reporting was effective as of December 31, 2012.

This annual report does not include an attestation report of the Company’s registered public accounting firm regarding internal control over financial report. Management’s report was not subject to attestation by the Company’s 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 annual report.

Changes in Internal Control over Financial Reporting

In preparation for management’s report on internal control over financial reporting, we documented and tested the design and operating effectiveness of our internal control over financial reporting. There were no changes in our internal controls over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) that occurred during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not Applicable

PART III

Item 10. Directors and Executive Officers Of The Registrant

The Directors and Executive Officers of the Company and certain information concerning them is set forth below:

Name	Age	Position
Chris G. Mazzini	55	Chairman of the Board, Director and President
Michelle H. Mazzini	51	Director, Vice President, Secretary, Treasurer
Ted R. Munselle	57	Director

On January 2, 2012, Mr. David E. Allard, resigned as a member of the Board of Directors of Spindletop Oil & Gas Co.

On February 17, 2012, Mr. Ted R. Munselle was appointed as a member of the Board of Directors of Spindletop Oil & Gas Co. Mr. Munselle is determined to have all the credentials and qualifications to be an Independent Financial Expert and has been appointed as an Independent Financial Expert for the Audit Committee of the Board of Directors and has been appointed as Chairman of the Audit Committee.

Except as set forth above, all directors hold offices until the next annual meeting of the shareholders or until their successors are duly elected and qualified. Officers of the Company serve at the discretion of the Board of Directors.

Business Experience

Chris Mazzini, Chairman of the Board of Directors and President, graduated from the University of Texas at Arlington in 1979 with a Bachelor of Science degree in Geology. He started his career in the oil and gas industry in 1978, and began as a Petroleum Geologist with Spindletop in 1979, working the Fort Worth Basin of North Texas. He became Vice President of Geology at Spindletop in 1982 and served in that capacity until he left the Company in 1985 when he founded Giant Energy Corp. ("Giant"). Mr. Mazzini has served as President of Giant since then. He rejoined the Company in December 1999 when he, through Giant, purchased controlling interest. Mr. Mazzini has been Chairman of the Board of Directors and President of the Company since 1999 and is a Certified and Licensed Petroleum Geologist. Mr. Mazzini has worked numerous geological basins throughout the United States with an emphasis on the Fort Worth Basin. He is responsible for several new field discoveries in the Fort Worth Basin.

Michelle Mazzini, Vice President and General Counsel, received her Bachelor of Science Degree in Business Administration (Major: Accounting) from the University of Southwestern Louisiana (now named University of Louisiana at Lafayette) where she graduated magna cum laude in 1985. She earned her law degree from Louisiana State University where she graduated Order of the Coif in 1988. Ms. Mazzini began her career with Thompson & Knight, a large law firm in Dallas, where she focused her practice on general corporate and finance transactions. She also worked as Corporate Counsel for Alcatel USA, a global telecommunications manufacturing corporation where her practice was broad-based. Ms. Mazzini serves as Vice President and General Counsel of the Company.

On February 17, 2012, Mr. Ted R. Munselle was appointed as a member of the Board of Directors of Spindletop Oil & Gas Co. Mr. Munselle is Vice President and Chief Financial Officer (since October 1998) of Landmark Nurseries, Inc. He is a Certified Public Accountant (since 1980) who was employed as an Audit Partner in two Dallas, Texas based CPA firms (1986 to 1998), as an Audit Manager at Grant Thornton, LLP (1983 to 1986) and as Audit Staff to Audit Supervisor at Laventhol & Horwath (1977 to 1983). Mr. Munselle is also a director (since February 2004) of American Realty Investors, Inc. and Transcontinental Realty Investors, Inc., both of which are Nevada corporations which have their common stock listed and traded on the New York Stock Exchange ("NYSE"), as well as a director (since May 2009) of Income Opportunity Realty Investors, Inc., a Nevada corporation which has its common stock listed and traded on the NYSE MKT.

Key and Technical Employees

In addition to the services provided by Mr. Mazzini and Ms. Mazzini (both of whom have biographies listed above), the Company also relies extensively on the key and the technical employees identified below.

Michael G. Boos, Geologist, earned a Bachelor of Science degree in Geology from the University of Delaware in 1979. After performing geophysical research for the State of Delaware seeking hydrothermal energy sources, Mr. Boos worked independently for many years as a Petroleum Exploration Consultant and as a Staff Explorationist for a local oil company. He has numerous field discoveries in the Mid-Continent to his credit. In 1993 Mr. Boos joined Spindletop's Geological Department. He pursued a Masters degree through the University of Texas system, and later worked as a Geologist and Senior Project Manager for several national environmental consulting firms until rejoining Spindletop in October, 2008. His petroleum exploration experience includes Alaska's North Slope (Prudhoe Bay), many of the continental U.S. producing basins, as well as Central and South America. He has testified as an expert witness before the Texas Railroad Commission (TRRC) on several occasions. He is a founding member of both the Geological Information Library of Dallas (GILD, now Geomap) and the American Association of Petroleum Geologists (AAPG) Environmental Division, and is a licensed Professional Geologist (P.G.) in the states of Texas and Tennessee.

Dave Chivvis, Petroleum Engineer, joined the Company in May, 2008. Mr. Chivvis earned his Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1993. After graduation, he worked for Cox Resources Corporation, an independent oil and gas company located in Dallas, Texas. Mr. Chivvis worked in various engineering areas from operations to acquisitions of oil and gas properties in Texas, Oklahoma, Louisiana, and Arkansas. He then moved to Los Angeles in 2001 to pursue other opportunities before moving back to Texas to join the Company.

Robert E. Corbin, Controller, has been a full-time employee of Spindletop since April 2002. From May 2001 until April 2002, Mr. Corbin was an Independent Accounting Consultant and devoted substantially all of his time to Spindletop. He has been active in the oil and gas industry for over 37 years, during which time he has served as financial officer of a publicly-held company as well as several private oil and gas companies and partnerships. Mr. Corbin graduated from Texas Tech University in 1969 with a BBA degree in Accounting and began his accounting career as an auditor with Arthur Andersen & Co. in 1970. Mr. Corbin is a Certified Public Accountant.

Charles (Chuck) D. Howell, Jr., Geologist, joined the Company in April, 2008. Mr. Howell earned a Bachelor of Science in Geology from Southern Methodist University in 1999. Currently, he is finishing his Ph.D. in Geology at the University of Texas at Dallas. Mr. Howell has been in the energy industry since 2003. He began his career at Pioneer Natural Resources working in the Gulf of Mexico. During 2005, Mr. Howell was an Independent Consulting Geologist for Anadarko Petroleum Corporation and worked on development of the historic Salt Creek Oil Field. In 2007, immediately before joining Spindletop Oil and Gas Company, he was a Geologist for Chevron Energy Technology Company in Houston, Texas and was part of a team of stratigraphic specialists for the West Coast of Africa. Mr. Howell is a long-standing and active member of the American Association of Petroleum Geologists, the Society for Sedimentary Geology, the Geological Society of America, the International Association of Sedimentologists, and remains associated with the Ichnology Research Group.

Dick A. Mastin, Petroleum Landman, has been a full-time employee of the Company since February, 2006. Mr. Mastin graduated cum laude from Stephen F. Austin State University in 1980 with a Bachelor of Science in Forestry and a minor in General Business. From September of 1980 until December of 1985, Mr. Mastin worked for Spindletop Oil & Gas Co. as a Petroleum Landman. He received his Masters of Science in Management and Administrative Sciences from the University of Texas at Dallas in 1990. In January of 1987, he took a position with the Dallas office of the Federal Bureau of Investigation. After a year with the Bureau, he accepted a position with the Internal Revenue Service as a Revenue Agent. Fifteen of his eighteen years with the Service were spent in the Large and Mid-Sized Business unit auditing tax returns of the largest business entities.

Glenn E. Sparks is the Land Director and also acts as Associate General Counsel to the Company. Mr. Sparks was previously employed as a Landman by the Company from 1982 through 1986, prior to attending law school. Mr. Sparks holds a B.B.A. with a concentration in Finance from the University of Texas at Arlington, and a J.D. from Texas Tech University School of Law. From 1990 to 2005, Mr. Sparks practiced law in a private practice focusing primarily on oil and gas law and real estate, as a partner in the law firm of Logan & Sparks, PLLC, and has acted as outside legal counsel for the Company in numerous oil and gas transactions during his years in private practice. Mr. Sparks left his private law practice and joined the Company again as an employee in his current position in 2005. Mr. Sparks is Board Certified in Oil & Gas Mineral Law by the Texas Board of Legal Specialization.

Family Relationships

Michelle Mazzini, Vice President, Secretary and General Counsel is the wife of Chris Mazzini, Chairman of the Board and President.

Involvement in Certain Legal Proceedings

None of the directors or executive officers of the Registrant, during the past five years, has been involved in any civil or criminal legal proceedings, bankruptcy filings or has been the subject of an order, judgment or decree of any Federal or State authority involving Federal or State securities laws.

Board Meetings and Committees

The Board of Directors met two times in 2012. The Board has established an audit committee. The Board is small and all members of the Board serve on the audit committee. The function of the audit committee is to assist the Board in fulfilling its oversight responsibilities by reviewing the financial information that will be provided to the shareholders and others, the systems of internal controls that management and the Board of Directors have established, and the audit process. During 2011, the audit committee was comprised of Mr. David Allard (Chairman), Mr. Chris Mazzini, and Ms. Michelle Mazzini. Subsequent to December 31, 2011, Mr. Allard resigned as a member of the Board of Directors and as Chairman of the Audit Committee. Effective with his appointment as a member of the Board of Directors of the Company on February 17, 2012, Mr. Munselle assumed the position of Chairman of the Audit Committee.

With respect to nominations to the Board, compensation, financial planning, strategies, and business alternatives, the Company does not have separate committees as the Board is small and all members of the Board participate in making recommendations and decisions on these matters.

Item 11. Executive Compensation

Cash Compensation

Cash compensation including salaries and bonuses, of $415,132, $295,686, and $297,038 was paid to Mr. Mazzini in 2012, 2011, and 2010 respectively. Cash compensation including salaries and bonuses of $281,950, $168,694, and $170,180 was paid to Ms. Mazzini in 2012, 2011, and 2010 respectively.

The Company has no stock option or incentive plan, does not grant any plan-based awards or awards of equity securities. The Company has no pension plan for its employees.

Compensation Pursuant to Plan

None

Other Compensation

Key employees and officers of the Company may sometimes be assigned overriding royalty interests and/or carried working interests in prospects acquired by or generated by the Company. These interests normally vary from less than one percent to three percent for each employee or officer. There is no set formula or policy for such program, and the frequency and amounts are largely controlled by the economics of each particular prospect. We believe that these types of compensation arrangements enable us to attract, retain and provide additional incentives to qualified and experienced personnel.

Effective August 1, 2011, the Company issued 10,000 shares of restricted common stock (5,000 shares to each of two individuals) pursuant to an employment package. The shares were valued at $1.70 per share, the believed market value for free trading shares at the time of issue. The amount was expensed as general and administrative expense. The shares of common stock were issued out of Treasury Stock and reduced the amount of the Company's common stock held in Treasury from 36,668 to 26,668 shares.

Effective December 30, 2011, the Company issued 10,000 shares of restricted common stock to a key employee pursuant to an employment package. The shares were valued at $1.70 per share, the believed market value for free trading shares at the time of issue. The amount was expensed as general and administrative expense. The shares of common stock were issued out of Treasury Stock and reduced the amount of the Company's common stock held in Treasury from 26,668 to 16,668 shares.

Compensation of Directors

Directors who are employees of the Company are not currently compensated for their services on the Board. Mr. Munselle was paid a director’s fee of $10,000 in 2012 to compensate him for his position as the Board of Directors’ Financial Expert. Mr. Munselle also received $2,500 for each Board of Directors’ meeting during the year other than the annual meeting. Mr. Munselle was paid a total of $12,500 in 2012. Mr. Allard was paid a director’s fee of $10,000 in 2011 and $12,500 in 2010.

Termination of Employment and Change of Control Arrangement

There are no plans or arrangements for payment to officers or directors upon resignation or a change in control of the Registrant.

Item 12. Security Ownership Of Certain Beneficial Owners And Management

Security Ownership of Certain Beneficial Owners and Managers

The table below sets forth the information indicated regarding ownership of the Registrant's common stock, $.01 par value, the only outstanding voting securities, as of April 1, 2013 with respect to: (i) any person who is known to the Registrant to be the owner of more than five percent of the Registrant's common stock; (ii) the common stock of the Registrant beneficially owned by each of the directors of the Registrant, and (iii) by all officers and directors as a group. Each person has sole investment and voting power with respect to the shares indicated, except as otherwise set forth in the footnotes to the table.

Name and Address of Beneficial Owner	Number of Shares	Nature of Beneficial Ownership *	Pct Based on Outstanding Percent of Class **
Chris Mazzini and Michelle Mazzini 12850 Spurling Rd., Suite 200 Dallas, Texas 75230	5,900,543	(1)	85.1%
All officers and directors as a group	5,900,543		85.1%

* "Beneficial Ownership" means the sole or shared power to vote, or direct the voting of, a security or investment power with respect to a security, or any combination thereof.

** Percentages are base upon 6,936,269 shares of Common Stock outstanding at April 1, 2013.

(1) Chris Mazzini directly owns 39,654 shares (0.5717%). Giant Energy Corp. directly owns 5,860,889 shares (84.4963%). Chris Mazzini owns 100% of the common stock of Giant Energy Corp.

Changes in control

The Company is not aware of any arrangements or pledges with respect to its securities that may result in a change in control of the Company.

Item 13. Certain Relationships And Related Transactions

Transactions with management and others

Certain officers, directors and related parties, including entities controlled by Mr. Mazzini, the President and Chief Executive Officer, have engaged in business transactions with the Company which were not the result of arm's length negotiations between independent parties. Our management believes that the terms of these transactions were as favorable to us as those that could have been obtained from unaffiliated parties under similar circumstances. All future transactions between us and our affiliates will be on terms no less favorable than could be obtained from unaffiliated third parties and will be approved by a majority of the disinterested members of our Board of Directors.

Chris G. Mazzini and Michelle H. Mazzini, through a limited partnership in which they are limited partners, own M-R Oilfield Services, LP ("MRO"), an oilfield service company which provides roustabout, swabbing and completion services at rates which are at or below market to the Company. This oilfield services company currently does work exclusively for the Company, its parent company, Giant Energy Corp. and Giant NRG, LP, although MRO is contemplating offering its services to unrelated third-parties. The Company benefits by having immediate access to services.

Certain Business Relationships

The long-term debt, which is secured by the commercial office building, is also guaranteed individually by Chris G. Mazzini and Michelle H. Mazzini, related parties.

On October 1, 2008, Giant entered into an Administrative Services Agreement with the Company whereby Giant pays the Company $250 per month for the Company providing administrative services to Giant.

The Company has entered into a management services agreement with MRO whereby MRO makes monthly payments in the amount of $1,000 per month to the Company in exchange for the Company providing administrative services to MRO. On October 1, 2008, the Company entered into a similar agreement with Giant NRG, LP (“NRG”) a limited partnership with Chris Mazzini and Michelle Mazzini as limited partners. Under this agreement NRG pays a monthly fee of $2,500 to the Company in exchange for the Company providing certain administrative services to NRG. The Company has entered into a similar arrangement with Peveler Pipeline, LP ("Peveler"), whereby Peveler pays the Company a monthly charge of $250 in exchange for the Company providing administrative services to Peveler. Chris and Michelle Mazzini are the owners of Peveler Pipeline, LP, a limited partnership which owns a pipeline gathering system servicing wells owned by Giant, another related entity, described elsewhere in this report. The Company entered into a similar agreement with M-R Ventures, LLC (“MRV”) a limited liability company that operates some wells in Michigan, and that is owned by Chris and Michelle Mazzini. Pursuant to this agreement, MRV pays the Company a monthly fee in the amount of $500 for certain administrative services that the Company provides to MRV. The Company entered into a similar agreement with Reserve Royalty Company (“Reserve”) a sole proprietorship that holds some royalty interests owned by Chris and Michelle Mazzini. Pursuant to this agreement, Reserve pays the Company a monthly fee in the amount of $350 for certain administrative services that the Company provides to Reserve. See also note 6 to the Financial Statements.

Item 14. Principal Accounting Fees and Services

The following table sets forth the aggregate fees for professional services rendered to Spindletop Oil & Gas Co. and Subsidiaries for the years 2012, 2011 and 2010 by accounting firm, Farmer, Fuqua, & Huff, P.C.

Type of Fees	2012	2011	2010
Audit Fees	$ 43,000	$ 43,000	$ 41,000
Audit Related Fees	—	—	—
Tax Fees	—	—	4,000
All other fees	—	—	—

Members of the Board of Directors (the "Board") fulfill the responsibilities of an audit committee and have established policies and Procedures for the approval and pre-approval of audit services and permitted non-audit services. The Board has the responsibility to engage and terminate Farmer, Fuqua, & Huff, P.C. independent auditors, to pre-approve their performance of audit services and permitted non-audit services, to approve all audit and non-audit fees, and to set guidelines for permitted non-audit services and fees. All the fees for 2012, 2011 and 2010 were pre-approved by the Board or were within the pre-approved guidelines for permitted non-audit services and fees established by the Board, and there were no instances of waiver of approved requirements or guidelines during the same periods.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

a. The following documents are filed as a part of this report:

(1) FINANCIAL STATEMENTS: The following financial statements of the Registrant and Report of Independent Registered Public Accounting Firm therein are filed as part of this Report on Form 10-K:

(2) FINANCIAL STATEMENT SCHEDULES:

Other financial statement schedules have been omitted because the information required to be set forth therein is not applicable, is immaterial or is shown in the consolidated financial statements or notes thereto.

(3) EXHIBITS: The following documents are filed as exhibits (or are incorporated by reference as indicated) into Report:

Exhibit Designation	Exhibit Description
3.1	Articles of Incorporation of Spindletop Oil & Gas Co. (previously filed with our General Form for Registration of Securities on Form 10, filed with the Commission on August 14, 1990)
3.2	Bylaws of Spindletop Oil & Gas Co. (previously filed with our General Form for Registration of Securities on Form 10, filed with the Commission on August 14, 1990)
14	Code of Ethics for Senior Financial Officers (Incorporated by reference to Exhibit 14 to the registrant's annual report Form 10-K for the fiscal year ended December 31, 2005)
21	Subsidiaries of the Registrant
31.1 *	Rule 13a-14(a) Certification of Chief Executive Officer
31.2 *	Rule 13a-14(a) Certification of Chief Financial Officer
32. *	Officers' Section 1350 Certifications

* Filed herewith

(b) The Index of Exhibits is included following the Financial Statement Schedules beginning at page 71 of this Report.

(c) The Index to Consolidated Financial Statements and Supplemental Schedules is included following the signatures, beginning at page 46 of this Report

SIGNATURES

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

SPINDLETOP OIL & GAS CO.

Date: April 15, 2013

By:/s/ Chris G. Mazzini
Chris G. Mazzini
President, Principal Executive Officer

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

Signatures Principal Executive Officers	Capacity	Date
/s/ Chris Mazzini Chris Mazzini	President, Director (Chief Executive Officer	April 15, 2013
/s/ Michelle Mazzini Michelle Mazzini	Vice President, Secretary, Treasurer, Director	April 15, 2013
/s/ Ted R. Munselle Ted R. Munselle	Director	April 15, 2013
/s/ Robert E. Corbin Robert E. Corbin	Controller (Principal Financial and Accounting Officer)	April 15, 2013

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
Index to Consolidated Financial Statements and Schedules

All other schedules have been omitted because they are not applicable, not required, or the information has been supplied in the consolidated financial statements or notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Shareholders of Spindletop Oil & Gas Co.

We have audited the accompanying consolidated balance sheets of Spindletop Oil & Gas Co. (A Texas Corporation) and subsidiaries as of December 31, 2012 and 2011, and the related consolidated statements of operations, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2012. Spindletop Oil & Gas Co.'s management is responsible for these consolidated financial statements. 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 consolidated financial statements are free of material misstatement. 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 consolidated 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 Spindletop Oil & Gas Co. and subsidiaries as of December 31, 2012 and 2011, and the consolidated results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America.

We were not engaged to examine management's assertion about the effectiveness of Spindletop Oil & Gas Co.'s internal control over financial reporting as of December 31, 2012 included in the accompanying management report on internal control over financial reporting and, accordingly, we do not express an opinion thereon.

Our audits were made for the purpose of forming an opinion on the basic consolidated financial statements taken as a whole. The schedules listed in the index of the consolidated financial statements are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic consolidated financial statements. These schedules have been subjected to the auditing procedures applied in the audits of the basic consolidated financial statements and, in our opinion, fairly state, in all material respects, the financial data required to be set forth therein in relation to the basic consolidated financial statements taken as a whole.

/s/ Farmer, Fuqua and Huff, P.C.

Richardson, Texas
April 15, 2013

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 7,151,000	$ 6,695,000
Accounts receivable, Trade	2,155,000	1,609,000
Prepaid income tax	—	405,000
Other short-term investments	400,000	400,000
Total Current Assets	9,706,000	9,109,000
Property and Equipment - at cost		
Oil and gas properties (full cost method)	22,822,000	20,395,000
Rental equipment	399,000	399,000
Gas gathering system	145,000	145,000
Other property and equipment	251,000	245,000
	23,617,000	21,184,000
Accumulated depreciation and amortization	(11,491,000)	(9,896,000)
Total Property and Equipment	12,126,000	11,288,000
Real Estate Property - at cost		
Land	688,000	688,000
Commercial office building	1,580,000	1,580,000
Accumulated depreciation	(653,000)	(601,000)
Total Real Estate Property	1,615,000	1,667,000
Other Assets		
Other long-term investments	1,200,000	1,200,000
Other	6,000	15,000
Total Other Assets	1,206,000	1,215,000
Total Assets	$ 24,653,000	$ 23,279,000

The accompanying notes are an integral part of these statements.

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2012	2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Notes payable, current portion	$ 120,000	$ 120,000
Accounts payable and accrued liabilities	3,451,000	3,222,000
Income tax payable	99,000	—
Tax savings benefit	97,000	97,000
Total Current Liabilities	3,767,000	3,439,000
Noncurrent Liabilities		
Notes payable, long-term portion	600,000	720,000
Asset Retirement obligation	949,000	946,000
Total Noncurrent Liabilities	1,549,000	1,666,000
Deferred Income Tax Payable	1,838,000	2,806,000
Total Liabilities	7,154,000	7,911,000
Shareholders' Equity		
Common Stock, $.01 par value, 100,000,000 shares authorized; 7,677,471 shares issued and 6,936,269 shares outstanding at December 31, 2012; 7,677,471 shares issued and 7,660,803 shares outstanding at December 31, 2011.	77,000	77,000
Additional paid-in capital	943,000	943,000
Treasury Stock, at cost	(1,536,000)	(8,000)
Retained earnings	18,015,000	14,356,000
Total Shareholder's Equity	17,499,000	15,368,000
Total Liabilities and Shareholders' Equity	$ 24,653,000	$ 23,279,000

The accompanying notes are an integral part of these statements.

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2012	2011	2010
Revenues			
Oil and gas revenues	$ 9,998,000	$ 8,000,000	6,302,000
Revenue from lease operations	359,000	289,000	319,000
Gas gathering, compression, equipment rental	145,000	172,000	179,000
Real estate rental income	242,000	436,000	448,000
Interest Income	78,000	83,000	158,000
Other	1,284,000	360,000	250,000
Total Revenues	12,106,000	9,340,000	7,656,000
Expenses			
Lease operations	2,631,000	2,444,000	1,901,000
Production taxes, gathering and marketing	891,000	809,000	712,000
Pipeline and rental operations	26,000	25,000	33,000
Real estate operations	185,000	225,000	246,000
Depreciation and amortization	1,647,000	1,152,000	1,042,000
ARO accretion expense	40,000	34,000	48,000
General and administrative	3,719,000	3,275,000	3,467,000
Interest expense	29,000	55,000	84,000
Total Expenses	9,168,000	8,019,000	7,533,000
Income Before Income Tax	2,938,000	1,321,000	123,000
Current income tax provision (benefit)	247,000	(229,000)	(97,000)
Deferred income tax provision (benefit)	(968,000)	(203,000)	(227,000)
Total income tax provision (benefit)	(721,000)	(432,000)	(324,000)
Net Income	$ 3,659,000	$ 1,753,000	447,000
Earnings per Share of Common Stock			
Basic and Diluted	$ 0.49	$ 0.23	$ 0.06
Weighted Average Shares Outstanding			
Basic and Diluted	7,541,352	7,645,858	7,631,652

The accompanying notes are an integral part of these statements.

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
For the Years Ended December 31, 2012, 2011, 2010

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock Shares	Treasury Stock Amount	Retained Earnings
Balance December 31,2009	7,677,471	$ 77,000	$ 901,000	46,668	$ (23,000)	$12,156,000
Issuance of 10,000 shares of Common Stock out of Treasury Stock as part of an employee compensation package			18,000	(10,000)	5,000	
Net Income (Loss)						$ 447,000
Balance December 31,2010	7,677,471	$ 77,000	$ 919,000	36,668	$ (18,000)	$12,603,000
Issuance of 10,000 shares of Common Stock out of Treasury Stock as part of an employee compensation package			12,000	(10,000)	5,000	
Issuance of 10,000 shares of Common Stock out of Treasury Stock as part of an employee compensation package			12,000	(10,000)	5,000	
Net Income (Loss)						$ 1,753,000
Balance December 31,2011	7,677,471	$ 77,000	$ 943,000	16,668	$ (8,000)	$14,356,000
Purchase of 700,000 shares of Common Stock as Treasury Stock				700,000	(1,491,000)	
Purchase of 24,534 shares of Common Stock as Treasury Stock				24,534	(37,000)	
Net Income (Loss)						$ 3,659,000
Balance December 31,2012	7,677,471	$ 77,000	$ 943,000	741,202	$(1,536,000)	$18,015,000

The accompanying notes are an integral part of these statements.

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Twelve Months Ended December 31,		
	2012	2011	2010
Cash Flows from Operating Activities			
Net Income	$ 3,659,000	$ 1,753,000	$ 447,000
Reconciliation of net income to net cash provided by operating activities			
Depreciation and amortization	1,647,000	1,152,000	1,042,000
Accretion of asset retirement obligation	40,000	34,000	48,000
Non-cash employee compensation paid with treasury stock	—	34,000	23,000
Changes in accounts receivable	(546,000)	(521,000)	(215,000)
Changes in prepaid income tax	405,000	41,000	—
Changes in accounts payable	229,000	946,000	(719,000)
Changes in current tax payable	99,000	—	136,000
Changes in deferred tax payable	(968,000)	(203,000)	668,000
Other	9,000	(12,000)	—
Net cash provided by operating activities	4,574,000	3,224,000	1,430,000
Cash Flows from Investing Activities			
Capitalized acquisition, exploration and development costs	(2,464,000)	(2,453,000)	(2,760,000)
Purchase of other property and equipment	(6,000)	—	(59,000)
Purchase of other short-term investments	—	—	(400,000)
Purchase of other long-term investments	—	(200,000)	(1,000,000)
Net cash used by investing activities	(2,470,000)	(2,653,000)	(4,219,000)
Cash Flows from Financing Activities			
Repayment of note payable to bank	(120,000)	(120,000)	(120,000)
Purchase of 724,534 shares of treasury stock	(1,528,000)	—	—
Net cash used by financing activities	(1,648,000)	(120,000)	(120,000)
Increase (decrease) in cash	456,000	451,000	(2,909,000)
Cash at beginning of period	6,695,000	6,244,000	9,153,000
Cash at end of period	$ 7,151,000	$ 6,695,000	$ 6,244,000

The accompanying notes are an integral part of these statements.

1. BASIS OF PRESENTATION AND ORGANIZATION

Merger and Basis of Presentation

On July 13, 1990, Prairie States Energy Co., a Texas corporation, (the Company) merged with Spindletop Oil & Gas Co., a Utah corporation (the Acquired Company). The name of Prairie States Energy Co. was changed to Spindletop Oil & Gas Co., a Texas corporation at the time of the merger.

Organization and Nature of Operations

The Company was organized as a Texas corporation in September 1985, in connection with the Plan of Reorganization ("the Plan"), effective September 9, 1985, of Prairie States Exploration, Inc., ("Exploration"), a Colorado corporation, which had previously filed for Chapter 11 bankruptcy. In connection with the Plan, Exploration was merged into the Company, with the Company being the surviving corporation. After giving effect to a stock split, up to a total of 166,667 of the Company's common shares may be issued to Exploration's former shareholders. As of December 31, 2011, 122,436 shares have been issued to former shareholders in connection with the Plan.

Spindletop Oil & Gas Co. is engaged in the exploration, development and production of oil and natural gas; and through one of its subsidiaries, the gathering and marketing of natural gas.

The Company owns land along with a commercial office building which contains approximately 46,286 of rentable square feet, of which the Company occupies approximately 12,759 rentable square feet as its corporate office headquarters. The Company leases the remaining space in the building to non-related third party commercial tenants at prevailing market rates.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A summary of the significant accounting policies consistently applied in the preparation of the accompanying financial statements follows:

FASB Accounting Standards Codification

The Company presents its financial statements in accordance with generally accepted accounting principles in the United States ("GAAP"). In June, 2009, the Financial Accounting Standards Board ("FASB") completed its accounting guidance codification project. The FASB Accounting Standards Codification ("ASC") became effective for the Company's financial statements issued subsequent to June 30, 2009 and is the single source of authoritative accounting principles recognized by the FASB to be applied to nongovernmental entities in the preparation of financial statements in conformity with GAAP. Accordingly, the Company refers to the ASC as the sole source of authoritative literature.

Consolidation

The consolidated financial statements include the accounts of Spindletop Oil & Gas Co. and its wholly owned subsidiaries, Prairie Pipeline Co. and Spindletop Drilling Company. All significant inter-company transactions and accounts have been eliminated.

Cash and Cash Equivalents

The Company considers all highly liquid instruments with a maturity of three months or less to be cash equivalents.

Other Investments

Other short-term and long-term investments consist of certificates of deposit with maturities of more than three months. Carrying amounts approximate fair value. Amounts for Changes in other short-term investments and Changes in other long-term investments in the Consolidated Statements of Cash Flows for 2010 have been reclassified to conform with the classifications shown in the 2011 Consolidated Statements of Cash Flows.

Allowance for Doubtful Accounts

The Company provides an allowance for doubtful accounts equal to the estimated uncollectible portion of accounts receivable. This estimate is based on historical collection experience and a review of the current status of accounts receivable.

Oil and Gas Properties

The Company follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs associated with acquisition, exploration and development of oil and gas reserves are capitalized and accounted for in cost centers, on a country-by-country basis. For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, shall not exceed an amount (the cost center ceiling) equal to the sum of:

a) The present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus
b) The cost of properties not being amortized; plus
c) The lower of cost or estimated fair market value of unproven properties included in the costs being amortized; less
d) Income tax effects related to differences between the book and tax basis of the properties.

If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling (as defined), the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts required to be written off will not be reinstated for any subsequent increase in the cost center ceiling. No impairment of oil and gas properties charge was recorded for 2012, 2011 or 2010.

Depreciation and amortization for each cost center are computed on a composite unit-of-production method, based on estimated proven reserves attributable to the respective cost center. All costs associated with oil and gas properties are currently included in the base for computation and amortization. Such costs include all acquisition, exploration, development costs and estimated future expenditures for proved undeveloped properties as well as estimated dismantlement and abandonment costs as calculated under the asset retirement obligation category, net of salvage value. All of the Company's oil and gas properties are located within the continental United States.

Gains and losses on sales of oil and gas properties are treated as adjustments of capitalized costs. Gains or losses on sales of property and equipment, other than oil and gas properties, are recognized as part of operations. Expenditures for renewals and improvements are capitalized, while expenditures for maintenance and repairs are charged to operations as incurred.

Property and Equipment

The Company, as operator, leases equipment to owners of oil and gas wells, on a month-to-month basis.

The Company, as operator, transports gas through its gas gathering systems, in exchange for a fee.

Depreciation is provided in amounts sufficient to relate the cost of depreciable assets to operations over their estimated service lives (5 to 10 years for rental equipment and gas gathering systems, 4 to 5 years for other property and equipment). The straight-line method of depreciation is used for financial reporting purposes, while accelerated methods are used for tax purposes.

Real Estate Property

The Company owns land along with a two-story commercial office building which is situated thereon. The Company occupies a portion of the building as its primary corporate headquarters, and leases the remaining space in the building to non-related third party commercial tenants at prevailing market rates. The Company depreciates the commercial office using the straight-line method of depreciation for financial statement and income tax purposes.

Investments in Real Estate

All investments in real estate holdings are stated at cost or adjusted carrying value. ASC Topic 360, "Accounting for the Impairment or Disposal of Long-Lived Assets", requires that a property be considered impaired if the sum of the expected future cash flows (undiscounted and without interest charges) is less than the carrying amount of the property. If impairment exists, an impairment loss is recognized by a charge against earnings equal to the amount by which the carrying amount of the property exceeds fair market value less cost to sell the property. If impairment of a property is recognized, the carrying amount of the property is reduced by the amount of the impairment, and a new cost for the property is established. Depreciation is provided over the properties estimated remaining useful life. There was no charge to earnings during 2012 due to impairment of real estate holdings.

Accounting for Asset Retirement Obligations

The Company adopted ASC Topic 410-20, "Accounting for Asset Retirement Obligations" on December 31, 2005. This statement requires the recording of a liability in the period in which an asset retirement obligation ("ARO") is incurred, in an amount equal to the discounted estimated fair value of the obligation that is capitalized. Thereafter, each quarter, this liability is accreted up to the final retirement cost. The determination of the ARO is based on an estimate of the future cost to plug and abandon our oil and gas wells. The actual costs could be higher or lower than current estimates.

The following table reflects the changes of the asset retirement obligations during the period ending December 31;

	2012	2011
Carrying amount of asset retirement obligation	$ 946,000	$ 854,000
Liabilities added	55,000	42,000
Liabilities divested or settled	(92,000)	16,000
Current period accretion expenses	40,000	34,000
Carrying amount as of December 31,	$ 949,000	$ 946,000

Revenue Recognition

The Company follows the “sales” (takes or cash) method of accounting for oil and gas revenues. Under this method, the Company recognizes revenues on oil and gas production as it is taken and delivered to the purchasers. The volumes sold may be more or less than the volumes the Company is entitled to take based on our ownership in the property. These differences result in a condition known as a production imbalance. Our crude oil and natural gas imbalances are insignificant.

Income Taxes

In June, 2006, an interpretation of ASC Topic 740-10, “Accounting for Uncertainty in Income Taxes” was issued. The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions. Federal and state tax authorities generally have the right to examine and audit the previous three years of tax returns filed.

The Company adopted the provisions of the interpretation of ASC Topic 740-10 effective January 1, 2007. The adoption of this accounting principle did not have an effect on the Company’s consolidated financial statements at, and for the three years ended December 31, 2012.

The Company accounts for income taxes pursuant to ASC Topic 740-10 "Accounting for Income Taxes" , which requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in the Company's financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement carrying amounts and tax bases of assets and liabilities, using enacted tax rates in effect in the years in which the differences are expected to reverse. The temporary differences primarily relate to depreciation, depletion and intangible drilling costs.

Use of Estimates

The preparation of financial statements in conformity with U. S. Generally Accepted Accounting Principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Share-Based Payments

Effective January 1, 2006, the Company adopted ASC Topic 718-10, “Share-Based Payment". ASC Topic 718-10 requires compensation costs related to share-based payments to be recognized in the income statement over the requisite service period. The amount of the compensation cost is to be measured based on the grant-date fair value of the instrument issued. ASC Topic 718-10 is effective for awards granted or modified after the date of adoption and for awards granted prior to that date that have not vested. ASC Topic 718-10 does not materially change the Company's existing accounting practices or the amount of share-based compensation recognized in earnings.

Recently Issued Accounting Pronouncements

Currently, there are no new accounting pronouncements that were issued to be effective in 2012 or subsequent thereto that would have a material impact on the Company’s financial reporting.

Subsequent Events

The Company has evaluated subsequent events through the issuance date of April 15, 2013.

3. ACCOUNTS RECEIVABLE

	December 31, 2012	December 31, 2011
Trade	$ 21,000	$ 101,000
Accrued receivable	2,149,000	1,523,000
	2,170,000	1,624,000
Less: Allowance for losses	(15,000)	(15,000)
	$ 2,155,000	$ 1,609,000

Accrued receivables are receivables from purchasers of oil and gas. These revenues are booked from check stub detail after receipt of the check for sales of oil and gas products. These payments are for sales of oil and gas produced in the reporting period, but for which payment has not yet been received until after the closing date of the reporting period. Therefore these sales are accrued as receivables as of the balance sheet date. Revenues for oil and gas production that has been sold but for which payment has not yet been received is accrued in the period sold.

4. ACCOUNTS PAYABLE

	December 31, 2012	December 31, 2011
Trade payables	$ 1,101,000	$ 1,170,000
Production proceeds payable	2,189,000	1,865,000
Prepaid drilling costs	161,000	187,000
	$ 3,451,000	$ 3,222,000

5. NOTES PAYABLE

	December 31, 2012	December 31, 2011
Note payable to a bank with monthly principal payments of $10,000 plus accrued interest at a variable annual interest rate based upon an index which is the Treasury securities rate for a term of seven years, plus 2.2%. The interest rate is subject to change on the first day of each seven year anniversary after the date of the rate based on the Index than in effect. As of the date of the loan, the annual interest rate was 6.11%. Effective December 27, 2011, the annual interest rate was adjusted to 3.61%. The note is collateralized by land and a commercial office building, plus a guarantee by certain related parties. The note matures in November, 2018.	720,000	840,000
Less current maturities	(120,000)	(120,000)
Total notes payable, long-term portion	600,000	720,000

Estimated annual maturities for long-term debt are as follows:

2013	120,000
2014	120,000
2015	120,000
2016	120,000
2017	120,000
thereafter	120,000
	720,000

6. RELATED PARTY TRANSACTIONS

On October 1, 2008, Giant entered into an Administrative Services Agreement with the Company whereby Giant agreed to pay the Company $250 per month for the Company providing administrative services to Giant. The Company also entered into a management services agreement with M-R Oilfield Services, LP (“MRO”), whereby MRO makes monthly payments in the amount of $1,000 to the Company in exchange for the Company providing administrative services to MRO. On October 1, 2008, the Company entered into a similar agreement with Giant NRG, LP (“NRG”), a limited partnership with Chris Mazzini and Michelle Mazzini as limited partners. Under this agreement NRG pays a monthly fee of $2,500 to the Company in exchange for the Company providing certain administrative services to NRG. The Company has entered into a similar arrangement with Peveler Pipeline, LP ("Peveler"), whereby Peveler pays the Company a monthly charge of $250 in exchange for the Company providing administrative services to Peveler. Chris and Michelle Mazzini are the owners of Peveler Pipeline, LP, a limited partnership which owns a pipeline gathering system servicing wells owned by Giant, another related entity, described elsewhere in this report. The Company entered into a similar agreement with M-R Ventures, LLC (“MRV”), a limited liability company that operates some wells in Michigan, and that is owned by Chris and Michelle Mazzini. Pursuant to this agreement, MRV pays the Company a monthly fee in the amount of $500 for certain administrative services that the Company provides to MRV. The Company entered into a similar agreement with Reserve Royalty Company (“Reserve”) a sole proprietorship that holds some royalty interests owned by Chris and Michelle Mazzini. Pursuant to this agreement, Reserve pays the Company a monthly fee in the amount of $350 for certain administrative services that the Company provides to Reserve.

The long-term debt, which is secured by the commercial office building, is also guaranteed individually by Chris G. Mazzini and Michelle H. Mazzini, related parties.

7. COMMON STOCK

Effective January 1, 2006, the Company adopted ASC Topic 718-10, "Share-Based Payment". ASC Topic 718-10 requires compensation costs related to share-based payments to be recognized in the income statement over the requisite service period. The amount of the compensation cost is to be measured based on the grant date fair value of the instrument issued. ASC Topic 718-10 is effective for awards granted or modified after the date of adoption and for awards granted prior to that date that have not vested. ASC Topic 718-10 does not materially change the Company's existing accounting practices or the amount of share-based compensation recognized in earnings.

Effective December 1, 2010, the Company issued 10,000 shares of restricted common stock to a key employee pursuant to an employment package. The shares were valued at $2.25 per share, the believed market value for free trading shares at the time of issue. The amount was expensed as general and administrative expense. The shares of common stock were issued out of Treasury Stock and reduced the amount of the Company's common stock held in Treasury from 46,668 to 36,668 shares.

Effective August 1, 2011, the Company issued 10,000 shares of restricted common stock (5,000 shares to each of two individuals) pursuant to an employment package. The shares were valued at $1.70 per share, the believed market value for free trading shares at the time of issue. The amount was expensed as general and administrative expense. The shares of common stock were issued out of Treasury Stock and reduced the amount of the Company's common stock held in Treasury from 36,668 to 26,668 shares.

Effective December 30, 2011, the Company issued 10,000 shares of restricted common stock to a key employee pursuant to an employment package. The shares were valued at $1.70 per share, the believed market value for free trading shares at the time of issue. The amount was expensed as general and administrative expense. The shares of common stock were issued out of Treasury Stock and reduced the amount of the Company's common stock held in Treasury from 26,668 to 16,668 shares.

The Company has not approved nor authorized any standing repurchase program for its common stock.

During the fourth quarter of the fiscal year ended December 31, 2012, the Company made the following repurchases of its common stock:

> Effective October 30, 2012, the Company repurchased 700,000 shares of its common stock for a purchase price of $1,491,000 or $2.13 per share.
>
> On December 18, 2012, the Company repurchased 24,534 shares of its common stock for a purchase price of $36,801 or $1.50 per share.

The repurchased shares are held as Treasury Stock.

8. INCOME TAXES

The Company accounts for income taxes pursuant to ASC Topic 740-10, "Accounting for Income Taxes". ASC Topic 740-10 utilizes the liability method of computing deferred income taxes.

In connection with the Plan discussed in Note 1, the Company agreed to pay, in cash, to Exploration's unsecured creditors, as defined, one-half of the future reductions of Federal income taxes which were directly related to any allowed carryovers of Exploration's net operating losses and investment tax credits. Such payments are to be made on a pro-rata basis. Amounts incurred under this agreement, which are considered contingent consideration, totaled $ -0-, $ -0-, and $ -0- in 2012, 2011 and 2010, respectively. As of December 31, 2012 the Company has not received a ruling from the Internal Revenue Service concerning the net operating loss and investment credit carryovers. Until the tax savings which result from the utilization of these carry-forwards is assured, the Company will not pay to Exploration's unsecured creditors any of the tax savings benefit. As of December 31, 2012, the Company owes $97,000 to Exploration's unsecured creditors.

In calculating tax savings benefits described above, consideration was given to the alternative minimum tax, where applicable, and the tax effects of temporary differences, as shown below:

Income tax differed from the amounts computed by applying an effective United States federal income tax rate of 34% to pretax income in 2012, 2011 and 2010 as a result of the following:

	2012	2011	2010
Computed expected tax expense (benefit)	$999,000	$449,000	$42,000
Miscellaneous timing differences related to book and tax depletion differences and the expensing of intangible drilling costs	(752,000)	(678,000)	(139,000)
Expected Federal income tax expense (benefit)	$247,000	$(229,000)	$(97,000)

Income tax expense (benefit) for the years ended December 31, 2012, 2011 and 2010 consisted of the following:

	2012	2011	2010
Federal income taxes (benefit)	$247,000	$(229,000)	$(97,000)
State income taxes	-	-	-
Current income tax provision (benefit)	$247,000	$(229,000)	$(97,000)

Deferred income taxes reflect the effects of temporary differences between the tax bases of assets and liabilities and the reported amounts of those assets and liabilities for financial reporting purposes. Deferred income taxes also reflect the value of investment tax credits and an offsetting valuation allowance. The Company's total deferred tax assets and corresponding valuation allowance at December 31, 2012 and 2011 consisted of the following:

	December 31,	
	2012	2011
Deferred tax assets		
Depreciation, depletion and amortization	770,000	238,000
Other, net	7,000	7,000
Total	777,000	245,000
Deferred tax liabilities		
Expired leasehold	(67,000)	(335,000)
Intangible drilling costs	(2,200,000)	(2,716,000)
Depreciation	(348,000)	-
Net deferred tax liability	$(1,838,000)	$(2,806,000)

9. CASH FLOW INFORMATION

The Company does not consider any of its assets, other than cash and certificates of deposit shown as cash on the balance sheet, to meet the definition of a cash equivalent.

Net cash provided by operating activities includes cash payments for the following:

	2012	2011	2010
Interest expense	$29,000	$55,000	$84,000
Income taxes	50,000	170,000	-

Excluded from the Consolidated Statements of Cash Flows were the effects of certain non-cash investing and financing activities, as follows:

	2012	2011	2010
Addition (Reduction) of Oil & Gas properties by recognition of asset retirement obligation	$(36,000)	$57,000	$45,000

10. EARNINGS PER SHARE

Earnings per share ("EPS") are calculated in accordance with ASC Topic 260-10, "Earnings per Share", which was adopted in 1997 for all years presented. Basic EPS is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period. The adoption of ASC Topic 260-10 had no effect on previously reported EPS. Diluted EPS is computed based on the weighted number of shares outstanding, plus the additional common shares that would have been issued had the options outstanding been exercised.

11. CONCENTRATIONS OF CREDIT RISK

Subsequent to December 31, 2012, FDIC Deposit insurance coverage changed. As scheduled, the unlimited insurance coverage for noninterest-bearing transaction accounts provided under the Dodd-Frank Wall Street Reform and Consumer Protection Act expired on December 31, 2012. Deposits held in non-interest-bearing transaction accounts are now aggregated with any interest-bearing deposits the owner may hold in the same ownership category, and the combined total insured up to at least $250,000.

Beginning January 1, 2013, noninterest-bearing transaction accounts will no longer be insured separately from depositors' other accounts at the same institution. Instead, noninterest-bearing transaction accounts will be added to any of a depositor's other accounts in the applicable ownership category, and the aggregate balance insured up to at least the Standard Minimum Deposit Insurance Amount (SMDIA) of $250,000, per depositor, at each separately chartered institution.

As of December 31, 2012 the Company had approximately $3,202,000 in checking and money market accounts at one bank, and approximately $3,058,000, which includes approximately $400,000 of long-term certificates of deposit, at a second bank. The Company also had approximately $3,295,000, including $400,000 of short-term certificates of deposit and $800,000 of long-term certificates of deposit invested at six other banking institutions. Cash amounts on deposit at these institutions exceeded current per account FDIC protection limits by approximately $3,325,000.

If the post 2012 FDIC coverage had been in effect at December 31, 2012, the Company's amounts on deposit would have exceeded the new FDIC protection limits by approximately $4,760,000.

Most of the Company's business activity is located in Texas. Accounts receivable as of December 31, 2012 and 2011 are due from both individual and institutional owners of joint interests in oil and gas wells as well as purchasers of oil and gas. A portion of the Company's ability to collect these receivables is dependent upon revenues generated from sales of oil and gas produced by the related wells.

12. FINANCIAL INSTRUMENTS

The estimated fair value of the Company's financial instruments at December 31, 2012 and 2011 follows:

	2012		2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash	$7,151,000	$7,151,000	$6,695,000	$6,695,000
Short-term certificates	400,000	400,000	400,000	400,000
Long-term certificates	1,200,000	1,200,000	1,200,000	1,200,000
Accounts receivable	2,155,000	2,155,000	1,609,000	1,609,000

The fair value amounts for each of the financial instruments listed above approximate carrying amounts due to the short maturities of these instruments.

13. COMMITMENTS AND CONTINGENCIES

In connection with the Plan of Reorganization discussed in Note 1, the Company agreed to pay, in cash, to Exploration's unsecured creditors, as defined, one-half of the future reduction of Federal income taxes which were directly related to any allowed carryovers of Exploration's net operating losses and investment tax credits existing at the time of the reorganization.

The Company's oil and gas exploration and production activities are subject to Federal, State and environmental quality and pollution control laws and regulations. Such regulations restrict emission and discharge of wastes from wells, may require permits for the drilling of wells, prescribe the spacing of wells and rate of production, and require prevention and clean-up of pollution.

Although the Company has not in the past incurred substantial costs in complying with such laws and regulations, future environmental restrictions or requirements may materially increase the Company's capital expenditures, reduce earnings, and delay or prohibit certain activities.

At December 31, 2012 the Company has acquired bonds and letters of credit issued in favor of various state regulatory agencies as mandated by state law in order to comply with financial assurance regulations required to perform oil and gas operations within the various state jurisdictions.

The Company has seven, $5,000 single-well bonds totaling $35,000 and one $10,000 single well bond with an insurance company, for wells the Company operates in Alabama. The $5,000 bonds are written for a three year period and the $10,000 bond is written for a one year period.

The Company has 10 letters of credit from a bank issued for the benefit of various state regulatory agencies in Texas, New Mexico, Oklahoma, and Louisiana, ranging in amounts from $10,000 to $50,000 and totaling $298,000. These letters of credit have expiration dates that range from January 1, 2013 through January 16, 2015 and are fully secured by funds on deposit with the bank in business money market accounts.

14. ADDITIONAL OPERATIONS AND BALANCE SHEET INFORMATION

Certain information about the Company's operations for the years ended December 31, 2012, 2011 and 2010 follows.

Sale of Oil & Gas Properties

In March, 2010, the Company sold its working interest and operations in the Robertson 20-12 well located in Lamar County, Alabama to an unrelated party for $5,000 in cash.

In December, 2012, the Company sold its working interest effective October 1, 2012, in 29 non-operated properties located in Palo Pinto, Wise, Jack, and Parker Counties, Texas to the operator of the wells for a gross sales price of $165,000.

Dependence on Customers

The following is a summary of significant purchasers / operators (listed by percent of total oil and natural gas sales) from oil and natural gas produced by the Company for the three-year period ended December 31, 2012:

Purchaser / Operator	2012	2011	2010
Shell Trading (US) Company	15%	20%	7%
Pruet Production Co.	9%	0%	0%
Enbridge Energy Partners	9%	22%	26%
Targa Midstream Service, LIM	8%	4%	3%
Halcon Resources Operating, Inc.	7%	0%	0%
Eastex Crude Company	6%	7%	7%
Crosstex Gulf Coast Mktg	5%	11%	16%
Panther Energy Company, LLC	4%	0%	0%
Gulfmark Energy, Inc.	4%	3%	0%
HollyFrontier Refining & Marketing LLC	3%	2%	3%
Petromax Operating Co., Inc.	3%	0%	0%
Sunoco Partners Marketing	3%	1%	1%
Encana Oil & Gas (USA), Inc.	3%	0%	0%
Enterprise Crude Oil, LLC	2%	5%	5%
Enervest Operating, LLC	2%	0%	0%
Sklar Exploration Co., LLC	2%	0%	0%
ETC Texas Pipeline	2%	2%	2%

Oil and gas is sold to approximately 100 different purchasers under market sensitive, short-term contracts computed on a month to month basis.

Except as set forth above, there are no other customers of the Company that individually accounted for more than two percent of the Company's oil and gas revenues during the three years ended December 31, 2012.

The Company currently has no hedged contracts.

Certain revenues, costs and expenses related to the Company's oil and gas operations are as follows:

	Year Ended December 31,		
	2012	2011	2010
Capitalized costs relating to oil and gas producing activities:			
Unproved properties	$2,267,000	$2,242,000	$2,064,000
Proved properties	20,555,000	18,153,000	15,820,000
Total capitalized costs	22,822,000	20,395,000	17,884,000
Accumulated amortization	(10,744,000)	(9,161,000)	(8,129,000)
Total capitalized costs, net	$12,078,000	11,234,000	$9,755,000

	Year Ended December 31,		
	2012	2011	2010
Costs incurred in oil and gas property acquistions, exploration and development:			
Acquistion of properties	$685,000	$303,000	$458,000
Development costs	1,742,000	2,208,000	2,346,000
Total costs incurred	$2,427,000	$2,511,000	$2,804,000

	Year Ended December 31,		
	2012	2011	2010
Results of operations from producing activities:			
Sales of oil and gas	$9,999,000	$8,000,000	$6,302,000
Production costs	3,521,000	3,253,000	2,613,000
Amortization of oil and gas properties	1,583,000	1,032,000	916,000
Total production costs	5,104,000	4,285,000	3,529,000
Total net revenue	$4,895,000	$3,715,000	$2,773,000

	Year Ended December 31,		
	2012	2011	2010
Sales price per equivalent Mcf	$7.88	$7.80	$6.22
Production costs per equivalent Mcf	$2.78	$3.17	$2.58
Amortization per equivalent Mcf	$1.25	$1.01	$0.90

	Year Ended December 31,		
	2012	2011	2010
Results of operations from gas gathering and equipment rental activities:			
Revenue	$145,000	$172,000	$179,000
Operating expenses	26,000	25,000	33,000
Depreciation	-	1,000	1,000
Total costs	26,000	26,000	34,000
Total net revenue	$119,000	$146,000	$145,000

15. BUSINESS SEGMENTS

The Company's three business segments are (1) oil and gas exploration, acquisition, production and operations, (2) transportation and compression of natural gas, and (3) commercial real estate investment. Management has chosen to organize the Company into the three segments based on the products or services provided. The following is a summary of selected information for these segments for the
three-year period ended December 31, 2012:

	Year Ended December 31,		
	2012	2011	2010
Revenues: (1)			
Oil and gas exploration, production and operations	$10,357,000	$8,289,000	$6,621,000
Gas gathering, compression and equipment rental	145,000	172,000	179,000
Real estate rental	242,000	436,000	448,000
	$10,744,000	$8,897,000	$7,248,000

	Year Ended December 31,		
	2012	2011	2010
Depreciation, depletion, and amortization expense:			
Oil and gas exploration, production and operations	$1,594,000	$1,050,000	$940,000
Gas gathering, compression and equipment rental	-	1,000	1,000
Real estate rental	53,000	101,000	101,000
	$1,647,000	$1,152,000	$1,042,000

	Year Ended December 31,		
	2012	2011	2010
Income from operations:			
Oil and gas exploration, production and operations	$5,201,000	$3,952,000	$3,020,000
Gas gathering, compression and equipment rental	119,000	146,000	145,000
Real estate rental	4,000	110,000	101,000
	5,324,000	4,208,000	3,266,000
Corporate and other (2)	(1,665,000)	(2,455,000)	(2,819,000)
Consolidated net income	$3,659,000	$1,753,000	$447,000

	Year Ended December 31,		
	2012	2011	2010
Identifiable assets net of DDA:			
Oil and gas exploration, production and operations	$12,126,000	$11,289,000	$9,829,000
Gas gathering, compression and equipment rental		(1,000)	
Real estate rental	1,615,000	1,667,000	1,767,000
	13,741,000	12,955,000	11,596,000
Corporate and other (3)	10,912,000	10,324,000	9,181,000
Consolidated total assets	$24,653,000	$23,279,000	$20,777,000

Note (1): All reported revenues are from external customers.

Note (2): Corporate and other includes general and administrative expenses, other non-operating income and expense and income taxes.

Note (3): Corporate and other includes cash, accounts and notes receivable, inventory, other property and equipment and intangible assets.

16. SUPPLEMENTARY INCOME STATEMENT INFORMATION

The following items were charged directly to expense:

	Year Ended December 31,		
	2012	2011	2010
Maintenance and repairs	$11,000	$15,000	$15,000
Production taxes	487,000	371,000	256,000
Taxes, other than payroll and income taxes	9,000	11,000	4,000

17. QUARTERLY DATA (UNAUDITED)

The table below reflects selected quarterly information for the years ended December 31, 2012, 2011 and 2010.

	Year Ended December 31, 2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$2,356,000	$2,940,000	$2,561,000	$4,249,000
Expense	(1,717,000)	(2,055,000)	(1,928,000)	(3,468,000)
Operating income (loss)	639,000	885,000	633,000	781,000
Current tax (provision) benefit	(78,000)	(66,000)	(3,000)	(100,000)
Deferred tax (provision) benefit	181,000	199,000	90,000	498,000
Net income (loss)	$742,000	$1,018,000	$720,000	$1,179,000
Earnings (loss) per share of common stock				
Basic and diluted	$0.10	$0.13	$0.09	$0.17

	Year Ended December 31, 2011			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$2,620,000	$2,077,000	$2,040,000	$2,603,000
Expense	(1,770,000)	(1,805,000)	(1,774,000)	(2,670,000)
Operating income (loss)	850,000	272,000	266,000	(67,000)
Current tax (provision) benefit	(79,000)	113,000	(12,000)	207,000
Deferred tax (provision) benefit	37,000	(104,000)	10,000	260,000
Net income (loss)	$808,000	$281,000	$264,000	$400,000
Earnings (loss) per share of common stock				
Basic and diluted	$0.10	$0.04	$0.03	$0.06

	Year Ended December 31, 2010			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenue	$1,968,000	$1,765,000	$1,831,000	$2,092,000
Expense	(1,523,000)	(1,631,000)	(1,810,000)	(2,569,000)
Operating income (loss)	445,000	134,000	21,000	(477,000)
Current tax (provision) benefit	(31,000)	(63,000)	244,000	(53,000)
Deferred tax (provision) benefit	(59,000)	76,000	(39,000)	249,000
Net income (loss)	$355,000	$147,000	$226,000	$(281,000)
Earnings (loss) per share of common stock				
Basic and diluted	$0.05	$0.02	$0.03	$(0.04)

18. SUPPLEMENTAL RESERVE INFORMATION (UNAUDITED)

The Company’s net proved oil and natural gas reserves as of December 31, 2012, 2011, and 2010 have been estimated by Company personnel.

All estimates are in accordance generally accepted petroleum engineering and evaluation principles and definitions and with guidelines established by the Securities and Exchange Commission. All of the Company’s reserves are located in the United States of America and accounted for under one cost center.

Our policies and practices regarding internal control over the estimating of reserves are structured to objectively and accurately estimate our oil and natural gas reserve quantities and present values in compliance with the U.S. Securities and Exchange Commission (“SEC”) regulations and accounting principles generally accepted in the United States of America. We maintain an internal staff of petroleum engineers and geosciences professionals who work closely with the accounting and financial departments to insure the integrity, accuracy and timeliness of data used in the estimation process. The data used in our reserve estimation process is based on historical results for production, oil and natural gas prices received, lease operating expenses and development costs incurred, ownership interest and other required data. Historical oil and gas prices, lease operating expenses, and ownership interests are provided by and verified by the Company’s accounting department.

The Petroleum Engineer responsible for the supervision and preparation of the Company’s internally generated reserve report has a Bachelor of Science degree in Petroleum Engineering from a major university and has experience in preparing economic evaluations and reserve estimates. He meets the requirements regarding qualifications, objectivity and confidentiality set forth in the Standards Pertaining to the Engineering and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The Company has established a written internal control procedure to verify that the data entered into our engineering evaluation software is complete and correct. These internal control procedures establish the source of the data both internally and externally, the personnel that will collect the data and testing of the data collected to ensure its accuracy.

The following reserve estimates were based on existing economic and operating conditions. Oil and gas prices for 2012, 2011, and 2010 were calculated using a 12-month average price, calculated as the un-weighted arithmetic average of the first-day-of-the month price for each month of each year. Operating costs, production and ad valorem taxes and future development costs were based on current costs with no escalation.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. Moreover, the present values should not be construed as the current market value of the Company's oil and gas reserves or the costs that would be incurred to obtain equivalent reserves.

Changes in Estimated Quantities of Proved Oil and Gas Reserves (Unaudited):

Quantities of Proved Reserves:	Crude Oil Bbls	Natural Gas Mcf
Balance December 31, 2009	322,880	12,521,130
Sales of reserves in place	—	(62,930)
Acquired properties	59,580	290,940
Extensions and discoveries	1,570	172,880
Revisions of previous estimates *	9,846	(1,475,633)
Production	(31,526)	(823,957)
Balance December 31, 2010	362,350	10,622,430
Sales of reserves in place	—	—
Acquired properties	11,390	122,310
Extensions and discoveries	36,610	226,300
Revisions of previous estimates *	70,338	(2,085,974)
Production	(48,708)	(733,816)
Balance December 31, 2011	431,980	8,151,250
Sales of reserves in place	(980)	(205,900)
Acquired properties	13,930	1,003,190
Extensions and discoveries	75,918	47,920
Revisions of previous estimates *	57,386	(1,671,752)
Production	(79,514)	(791,708)
Balance December 31, 2012	498,720	6,533,000

* May also include divestitures, not only changes in engineering.

Proved Developed Reserves:		
Balance December 31, 2010	361,870	8,754,920
Balance December 31, 2011	401,240	8,124,340
Balance December 31, 2012	498,720	6,533,000

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves (Unaudited)

The Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves ("Standardized Measures") does not purport to present the fair market value of a company's oil and gas properties. An estimate of such value should consider, among other factors, anticipated future prices of oil and gas, the probability of recoveries in excess of existing proved reserves, the value of probable reserves and acreage prospects, and perhaps different discount rates. It should be noted that estimates of reserve quantities, especially from new discoveries, are inherently imprecise and subject to substantial revision.

Reserve estimates were prepared in accordance with standard Security and Exchange Commission guidelines. The future net cash flow for 2012, 2011, and 2010, was computed using a 12-month average price, calculated as the un-weighted arithmetic average of the first-day-of-the month price for each month of the year. Lease operating costs, compression, dehydration, transportation, ad valorem taxes, severance taxes, and federal income taxes were deducted. Costs and prices were held constant and were not escalated over the life of the properties. No deduction has been made for interest, or general corporate overhead. The annual discount of estimated future cash flows is defined, for use herein, as future cash flows discounted at 10% per year, over the expected period of realization.

Proved Developed Reserves were calculated based on Decline Curve Analysis on 77 operated wells and 86 non-operated wells. Materially insignificant operated and non-operated wells were excluded from the reserve estimate.

The Company emphasizes that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is reasonably possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Standardized measure of discounted future net cash flows related to proved reserves:

	Year Ended December 31,		
	2012	2011	2010
Future production revenue	$ 68,813,000	$ 78,938,000	$ 72,465,000
Future development costs	(108,000)	(108,000)	(2,187,000)
Future production costs	(29,746,000)	(32,843,000)	(32,386,000)
Future net cash flow before Federal income taxes	38,959,000	45,987,000	37,892,000
Future income taxes	(10,909,000)	(12,876,000)	(10,610,000)
Future net cash flows	28,050,000	33,111,000	27,282,000
Effect of 10% annual discounting	(5,787,000)	(9,649,000)	(8,577,000)
Standardized measure of discounted cash flows	$ 22,263,000	$ 23,462,000	$ 18,705,000

Changes in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2012	2011	2010
Beginning of the year	$ 23,462,000	$ 18,705,000	$ 16,110,000
Sales of oil and gas, net of production costs	(6,161,000)	(4,516,000)	(3,510,000)
Net changes in prices and production costs	(2,990,000)	5,970,000	3,713,000
Extensions, discoveries, additions less related costs	3,498,000	2,179,000	377,000
Development costs incurred	1,657,000	2,101,000	1,936,000
Net changes in future development cost	7,000	(1,492,000)	(581,000)
Revisions of previous quantity estimates	(1,742,000)	(1,243,000)	(2,131,000)
Net change in purchase and sales of minerals in place	1,051,000	581,000	1,318,000
Accretion of discount	2,346,000	1,871,000	1,611,000
Net change in income taxes	1,502,000	(417,000)	152,000
Other	(367,000)	(277,000)	(290,000)
End of year	$ 22,263,000	$ 23,462,000	$ 18,705,000

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED DECEMBER 31, 2012, 2011, AND 2010

SCHEDULE II

	Balance	Costs & Expenses	Deductions	Ending Balance
Allowance for doubtful accounts				
December 31, 2010	$ 14,000	$ 24,000	$ 23,000	$ 15,000
December 31, 2011	$ 15,000	$ —	$ —	$ 15,000
December 31, 2012	$ 15,000	$ —	$ —	$ 15,000

SCHEDULE III

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES
REAL ESTATE AND ACCUMULATED DEPRECIATION

	Initial Cost to Corporation			Total Cost
Description	Encumbrances	Land	Buildings	Subsequent to Acquisition
Two story multi-tenant garden office building with sub-grade parking garage located in Dallas, Texas	(b)	$ 688,000	$ 1,298,000	$ 282,000

Gross amounts at which carried at close of year

Land	Buildings	Total	Accumulated Depreciation	Life on which Depreciation Calculated	Date Acquired
$ 688,000	$ 1,580,000	$ 2,268,000	$ 653,000	(a)	12/27/2004

Notes to Schedule III

(a) See Footnote 2 to the Financial Statements outlining depreciation methods and lives.

(b) See description of notes payable in Footnote 5 to the Financial Statements outlining the terms and provisions of the acquisition loan for the building.

(c) The reconciliation for investments in real estate and accumulated depreciation for the years ended December 31, 2012 are as follows

	Investments in Real Estate	Accumulated Depreciation
Balance, December 31, 2005	$ 1,986,000	$ 49,000
Acquisitions	210,000	
Depreciation expense		71,000
Balance, December 31, 2006	2,196,000	120,000
Acquisitions	34,000	
Depreciation expense		84,000
Balance, December 31, 2007	2,230,000	204,000
Acquisitions	38,000	
Depreciation expense		96,000
Balance, December 31, 2008	2,268,000	300,000
Acquisitions		
Depreciation expense		100,000
Balance, December 31, 2009	2,268,000	400,000
Acquisitions		
Depreciation expense		101,000
Balance, December 31, 2010	2,268,000	501,000
Acquisitions		
Depreciation expense		100,000
Balance, December 31, 2011	2,268,000	601,000
Acquisitions		
Depreciation expense		52,000
Balance, December 31, 2012	$ 2,268,000	$ 653,000

Exhibit 21

SPINDLETOP OIL & GAS CO. AND SUBSIDIARIES

Subsidiaries of the Registrant

Spindletop Drilling Company, incorporated September 5, 1975, under the laws of the State of Texas, is a wholly owned subsidiary of the Registrant.

Prairie Pipeline Co. incorporated June 22, 1983, under the laws of the State of Texas, is a wholly owned subsidiary of Registrant.

Exhibit 31.1

CERTIFICATIONS

I, Chris G. Mazzini, certify that:

1. I have reviewed this report on Form 10-K of Spindletop Oil & Gas Co.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13-15(e) and 15d-15e) 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 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 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 officers 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 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 controls.

Date: April 15, 2013

By:/s/ Chris G. Mazzini
Chris G. Mazzini
President, Principal Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Robert E. Corbin, certify that:

1. I have reviewed this report on Form 10-K of Spindletop Oil & Gas Co.;

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

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

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13-15(e) and 15d-15e) 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 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 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 officers 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 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 controls.

Date: April 15, 2013

By:/s/ Robert E. Corbin
Robert E. Corbin
Controller, Principal Financial and Accounting 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 Annual Report of Spindletop Oil & Gas Co. (the "Company"), on Form 10-K for the year ended December 31, 2012 as filed with the Securities Exchange Commission on the date hereof (the "Report"), the undersigned Principal Executive Officer and Principal Financial and Accounting Officer of the Company, do hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Date: April 15, 2013

By:/s/ Chris G. Mazzini
Chris G. Mazzini
President, Principal Executive Officer

By:/s/ Robert E. Corbin
Robert E. Corbin
Controller, Principal Financial and
Accounting Officer