Sanchez Energy Corp
Form 424B4
December 14, 2011
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Registration No. 333-176613

PROSPECTUS

10,000,000 Shares

Sanchez Energy Corporation

COMMON STOCK

Sanchez Energy Corporation is offering 10,000,000 shares of its common stock. This is the initial public offering of our common stock and no public market currently exists for our common stock. Our common stock has been approved for listing on the New York Stock Exchange under the symbol SN.

Investing in our common stock involves risks. See Risk Factors beginning on page 19.

	Per Share	Total
Initial Public Offering Price	$ 22.00	$ 220,000,000
Underwriting Discounts and Commissions	$ 1.43	$ 14,300,000
Proceeds, Before Expenses, to Us	$ 20.57	$ 205,700,000

The underwriters may also purchase up to an additional 1,500,000 shares of common stock from us at the public offering price, less the underwriting discounts and commissions, within 30 days of the date of this prospectus to cover any over-allotments. If the underwriters exercise this option in full, the total underwriting discounts and commissions will be $16,445,000, and our total proceeds, after underwriting discounts and commissions, will be $236,555,000.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved of these securities, or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to purchasers on December 19, 2011.

Johnson Rice & Company L.L.C. **Macquarie Capital**

Simmons & Company

International

Canaccord Genuity

Capital One Southcoast

Cowen and Company

Stifel Nicolaus Weisel

December 13, 2011

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You should rely only on the information contained in this prospectus or in any free writing prospectus we may authorize to be delivered to you. Neither we nor the underwriters have authorized anyone to provide you with additional or different information. We and the underwriters are offering to sell, and seeking offers to buy, shares of common stock only in jurisdictions where offers and sales are permitted.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. Please read Risk Factors and Forward-Looking Statements.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Although we believe these third-party sources are reliable and that the information is accurate and complete, we have not independently verified the information nor have we ascertained the underlying economic or operational assumptions relied upon therein.

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. Because this summary provides only a brief overview of the key aspects of the offering, it does not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully, including Risk Factors beginning on page 19, Management s Discussion and Analysis of Financial Condition and Results of Operations beginning on page 55 and the financial statements and the related notes appearing elsewhere in this prospectus, before making an investment decision. The information presented in this prospectus assumes that the underwriters do not exercise their option to purchase additional shares of common stock from us, unless otherwise indicated.

As used in this prospectus, unless otherwise indicated: (i) the company, we, our, us or similar terms refer collectively to Sanchez Energy Corporation and its operating subsidiaries after giving effect to the formation transactions described under Formation Transactions ; (ii) SOG refers to Sanchez Oil & Gas Corporation, a Delaware corporation; (iii) SEP I refers to Sanchez Energy Partners I, LP, a Delaware limited partnership; (iv) Sanchez Group refers to SOG, SEP I and their affiliates (but excludes the company); (v) SEP Holdings III refers to SEP Holdings III, LLC, a Delaware limited liability company and a wholly owned subsidiary of SEP I, which will be contributed to us as part of the formation transactions; and (vi) Marquis LLC refers to SN Marquis LLC, the Delaware limited liability company that will be contributed to us by Ross Exploration, Inc., or Ross Exploration, in connection with the Marquis acquisition described below. See Organizational Structure of Sanchez Energy Corporation for additional information.

On November 8, 2011, we entered into a contribution agreement with Ross Exploration to acquire, through the acquisition of Marquis LLC, approximately 54,900 net undeveloped acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. This transaction is referred to as the Marquis acquisition throughout this prospectus and is one of the formation transactions described under Formation Transactions. The Marquis acquisition is subject to a limited number of closing conditions, including completion of this offering, and is expected to close immediately after the closing of this offering. See Recent Developments and The Marquis Acquisition. Our net acreage, the number of identified drilling locations and wells, and capital expenditures are presented throughout this prospectus after giving effect to the Marquis acquisition.

Our estimated proved reserve information as of December 31, 2010 and June 30, 2011 is based on reports prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. We have included a glossary of some of the oil and natural gas terms used in this prospectus in Appendix A.

Overview

We are an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources and recently formed for the purpose of acquiring unconventional oil and natural gas assets, including those that will be contributed to us as part of the formation transactions. We have accumulated approximately 92,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale in Gonzales, Zavala, Frio, Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. Approximately 54,900 net acres of the 92,000 net acres are attributable to the properties to be acquired as part of the Marquis acquisition. We use the term black oil to describe a quality of oil with an API gravity of 40º or less and with a gas-to-oil ratio of 500 cubic feet per barrel or less. We use the term volatile oil to describe a quality of oil with an API gravity greater than 40º and with a gas-to-oil ratio of greater than 500 cubic feet per barrel. The majority of our capital expenditure budget for the period from January 2012 through December 2013 will be focused on the development and expansion of our oil focused Eagle Ford Shale acreage and operations. We plan to continue to aggressively pursue additional leasehold and strategic acquisitions in the Eagle Ford Shale.

Our management team and the Sanchez Group have a proven track record in identifying, acquiring, and executing large drilling programs and have operated a wide range of drilling projects over the last 40 years, primarily focused as an operator in the South Texas and onshore Gulf Coast areas. Various members of the

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Sanchez Group have been in the oil and natural gas business since 1972, have drilled or participated in over 900 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry. During this period, they have carefully cultivated their relationships with mineral and surface rights owners in and around our South Texas and onshore Gulf Coast areas, which we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas.

Our Eagle Ford Shale acreage is comprised of approximately 9,400 net acres in Gonzales County, Texas, which we refer to as our Palmetto area, approximately 27,700 net acres in Zavala and Frio Counties, Texas, which we refer to as our Maverick area, and approximately 54,900 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas included in the Marquis acquisition, which we refer to as the Marquis area. Hilcorp Energy Company, together with its affiliates, or Hilcorp, recently closed the sale of 141,000 net acres in the Eagle Ford Shale, including its 50% ownership interest in our Palmetto area, to Marathon Oil Corporation, or Marathon, for approximately $3.5 billion, or an average of $24,822 per net acre, before adjusting for acquired production and reserves and subject to closing adjustments. Marathon is now our 50/50 working interest partner in our Palmetto area, as successor to Hilcorp.

We own all rights and depths on the majority of our Eagle Ford Shale acreage. We believe this acreage to be prospective for other zones, including the Buda Limestone, Austin Chalk and Pearsall Shale formations that lie above and below the Eagle Ford Shale. We are currently evaluating these other zones, which may present us with additional drilling locations. Several of our existing wells are either producing from or have logged pay in the Buda Limestone and the Austin Chalk formations.

In addition, we have approximately 1,250 net acres in the Haynesville Shale in Natchitoches Parish, Louisiana, which are operated by Chesapeake Energy Corporation. We do not currently anticipate spending any capital on our Haynesville acreage in the near future. The majority of our Haynesville leases extend through 2012 and 2013, giving us and our partners the option to accelerate drilling should natural gas prices increase. Finally, we have amassed approximately 82,000 net acres in northern Montana, which we believe may be prospective for the Heath, Three Forks and Bakken Shales.

Our capital expenditure budget for the period from January 2012 through December 2013 is approximately $413 million, and is anticipated to consist of the following:

- Approximately $350 million for drilling and completing wells in the Eagle Ford Shale;
- Approximately $50 million for expansion of our Eagle Ford Shale acreage position; and
- Approximately $13 million for construction of central facilities for our Eagle Ford Shale acreage.

The following table presents summary data for each of our primary project areas as of September 30, 2011, unless otherwise indicated:

				Capital Expenditure Budget from January 2012 through December 2013			
	Net	Identified Drilling Locations[1]				Drilling	Estimated Net Proved Reserves[2]
	Acreage	Gross	Net	Gross Wells	Net Wells	Capex (in millions)	(mmboe)
Palmetto Gonzales[3]	9,392	156	76	39	19	$ 165	2.9
Maverick Zavala, Frio	27,711	285	230	18	9	50	0.1
Marquis Fayette, Lavaca, Atascosa, Webb and DeWitt	54,868	457	457	18	18	135	-
Total Eagle Ford Shale	91,971	898	763	75	46	$ 350	3.0
Haynesville Shale	1,252	60	15	-	-	-	0.2

Heath, Three Forks and Bakken Shales	82,274	-	-	-	-		-	-
Total	175,497	958	778	75	46	$	350	3.2

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(1) Total identified drilling locations are calculated using approximately 120 acre spacing in our Eagle Ford Shale areas and approximately 80 acre spacing in our Haynesville Shale area on the undeveloped portion of our acreage. We are currently evaluating our acreage in the Heath, Three Forks and Bakken Shales and have not identified any drilling locations on that acreage.

(2) Based on Ryder Scott estimated proved reserve report as of June 30, 2011.

(3) In our Palmetto area, we have 19 gross (9.5 net) locations that are classified as proved undeveloped at June 30, 2011. We plan to drill all of those proved undeveloped locations within the next five years.

The table above identifies a total of up to 958 gross (778 net) drilling locations, of which over 90% are located in our Eagle Ford Shale acreage position. Our Ryder Scott estimated proved reserve report dated as of June 30, 2011 attributed proved undeveloped reserves to 20 gross locations of these total identified locations, one of which was placed on production subsequent to June 30, 2011. In addition, this reserve report attributed probable undeveloped reserves to 84 gross locations and possible undeveloped reserves to 75 gross locations.

Our Properties

Eagle Ford Shale

The Eagle Ford Shale is one of the fastest growing unconventional shale trends in North America. According to the Smith Weekly Rig Count, since January 2010, the rig count in the Eagle Ford Shale has grown 659% from 27 rigs to 205 rigs as of November 11, 2011. Based on a recent study by the Society of Petroleum Engineers, the aerial extent of the trend is thought to be approximately 11 million acres. Based on publicly available information, we believe that average drilling and completion costs in the trend have ranged between $5.5 million and $9.5 million per well with average estimated ultimate recoveries, or EURs, ranging from 225,000 to 850,000 boe per well, and initial 30-day average production has ranged between 200 to 2,000 boe/d per well. There have been a number of recent publicly-reported transactions in the trend that have yielded per acre valuations ranging from approximately $5,000 per acre to $25,000 per acre. Based on our experience and that of other companies operating in this trend, we believe that the Eagle Ford Shale can be characterized as having low geologic risks and repeatable drilling opportunities.

In the Eagle Ford Shale, we have assembled approximately 92,000 net acres with an average working interest of approximately 85%. Using approximately 120 acre well-spacing for horizontal well development, we believe that there could be up to 898 gross (763 net) locations for potential future drilling on our acreage. Consistent with other operators in this area, we plan to perform multi-stage hydraulic fracturing with 12 to 20 stages on each lateral well. For the period from January 2012 through December 2013, we plan to spend approximately $350 million on drilling 75 gross (46 net) wells on our Eagle Ford Shale acreage.

In our Palmetto area, we have approximately 9,400 net acres in Gonzales County, Texas with an average working interest of approximately 49%. We believe that our Palmetto acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $7.5 million and $9.5 million per well based on publicly available information. We have participated in the drilling of four gross wells on our acreage that had an average initial 30-day per well choke restricted production rate of 788 boe/d (665 bopd and 737 mcf/d). We have identified up to 156 gross (76 net) locations based on 120 acre spacing for potential future drilling in our Palmetto area. For the period from January 2012 through December 2013, we plan to spend approximately $165 million to drill 39 gross (19 net) wells in our Palmetto area.

In our Maverick area, we have approximately 27,700 net operated acres in Zavala and Frio Counties, Texas with an average working interest of approximately 81%. We believe that our Maverick acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 million and $6.5 million per well based on publicly available information. We have identified up to 285 gross (230 net) locations based on 120 acre spacing for potential future drilling on our Maverick acreage.

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We have drilled one horizontal well that had an initial 30-day average production rate of 242 bopd. We are currently drilling one vertical well to also test the feasibility of a vertical development program and compare horizontal and vertical completion economic returns. For the period from January 2012 through December 2013, we plan to spend approximately $50 million to drill 18 gross (9 net) wells in our Maverick area.

In our Marquis area, we have approximately 54,900 net operated acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We believe that our Marquis acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $6.5 million and $8.5 million per well based on publicly available information. We have identified up to 457 gross and net locations based on 120 acre spacing for potential future drilling on our Marquis acreage. Other operators in this project area have recently reported initial per well production rates of 1,000 to 1,200 boe/d. For the period from January 2012 through December 2013, we plan to spend approximately $135 million to drill 18 gross (18 net) wells in our Marquis area. Our net acreage, the number of identified drilling locations and wells, and capital expenditures are presented throughout this prospectus after giving effect to the Marquis acquisition.

Haynesville Shale

We have assembled approximately 1,250 net acres in Natchitoches Parish, Louisiana that are prospective for the Haynesville Shale. We have an average working interest of approximately 25% and the operator on our Haynesville Shale acreage is Chesapeake Energy Corporation. Three gross wells have been drilled to date, and we have participated in one of those wells. We believe that our acreage position is in the core of the Haynesville Shale fairway. We anticipate drilling, completion and facilities costs on our acreage to be between $8.0 and $10.0 million per well. We have identified 60 gross and 15 net locations for potential future drilling on our acreage. We do not currently anticipate spending any capital on our Haynesville Shale acreage in the near term. The majority of our Haynesville Shale leases extend through 2012 and 2013, giving us and our partners the option to accelerate drilling should natural gas prices increase.

Heath, Three Forks and Bakken Shales

We have acquired approximately 82,000 net acres in Lewis and Clark, Meagher, and Cascade Counties of Montana that we believe may be prospective for the Heath, Three Forks and Bakken Shales. We plan to monitor industry activity in our area as we develop our plans. Our lease terms are for five years with an option to renew for another five years at $10 per acre, giving us time to allow industry activity to develop the trend before we devote significant drilling capital to our acreage position.

Our Business Strategies

Our primary business objective is to increase stockholder value by building reserves, production and cash flows at an attractive return on invested capital. To achieve our objective, we intend to execute the following business strategies:

- A*ggressively Develop Our Eagle Ford Shale Leasehold Positions.* We intend to aggressively drill and develop our acreage position to maximize the value of our resource potential. The up to 898 gross (763 net) locations for potential future drilling that we have identified in our Eagle Ford Shale area will be our primary targets in the near term as we believe the Eagle Ford Shale to be the highest rate of return project that we currently possess. We anticipate drilling 75 gross (46 net) wells through December 2013 with an aggregate drilling and completion capital expenditure budget of approximately $350 million.

- *Pursue Strategic Acquisitions and Grow Our Leasehold Position in the Eagle Ford Shale and Seek Entry into New Basins.* We believe that we will be able to identify and acquire additional acreage and producing assets in the Eagle Ford Shale. We recently entered into a definitive agreement to acquire approximately 54,900 net acres from Ross Exploration for approximately $89 million in cash, subject to adjustment, 909,091 shares of our common stock and a previously conveyed overriding royalty interest in what is now our Marquis area. By leveraging our longstanding relationships in South Texas, we plan on continuing to expand our Eagle Ford Shale acreage position at what we believe to be attractive valuations, and we have budgeted $50 million for additional leasehold acquisitions in the Eagle Ford Shale for the period between January 2012 and December 2013. We also plan to selectively target additional domestic basins that would allow us to employ our strategies on large undeveloped acreage positions similar to our Eagle Ford Shale acreage.

Leverage our Relationship with Our Affiliates to Expand Unconventional Oil Assets. Our largest stockholder is controlled by certain members of the Sanchez Group. Various members of the Sanchez Group have drilled or participated in over 900 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry since 1972. During this period, they have carefully cultivated their relationships with mineral and surface rights owners in and around our South Texas and onshore Gulf Coast areas and compiled an extensive technological database, which we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas. We will have access to the unrestricted, proprietary portions of the technological database related to our properties, and SOG will otherwise be required to interpret and use the database, to the extent relating to our properties for our benefit. The majority of the database covers the South Texas and onshore Gulf Coast areas and includes more than 6,400 square miles of 3D seismic data and 48,000 miles of 2D seismic data used for regional interpretation, 395,000 well logs, 13,000 LAS files and 30,000 scanned well documents, as well as a fully integrated suite of the latest interpretive geologic software. We plan on leveraging our affiliates expertise, industry relationships and size to opportunistically expand reserves and our leasehold positions in the Eagle Ford Shale and other onshore unconventional oil resources.

Enhance Returns by Focusing on Operational and Cost Efficiencies. We are focused on continuous improvement of our operating measures and have significant experience in successfully converting early-stage resource opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our project areas provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad, utilizing centralized production and fluid handling facilities and reducing the time and cost of rig mobilization.

Adopt and Employ Leading Drilling and Completion Techniques. We are focused on enhancing our drilling and completion techniques to maximize recovery. Industry techniques with respect to drilling and completion have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of longer laterals and more tightly spaced fracturing stimulation stages. We continuously evaluate industry drilling results and monitor the results of other operators to improve our operating practices, and we expect our drilling and completion techniques will continue to evolve.

Maintain Substantial Financial Liquidity to Capitalize on Opportunity and Limit Commodity Price Volatility. Following the completion of this offering and the other transactions described under Formation Transactions, we will have approximately $64 million in cash and no outstanding indebtedness. We believe this strong liquidity position will allow us to grow production and proved reserves, to capitalize on acreage acquisition opportunities and to weather any potential volatility in commodity prices. We currently expect that the net proceeds

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from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our available liquidity options.

Our Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies:

Geographically Concentrated Leasehold Position in One of North America s Leading Unconventional Oil Resource Trends. We have assembled a current leasehold position of approximately 92,000 net leasehold acres in the Eagle Ford Shale, which we believe to be one of the highest rates of return unconventional oil and natural gas areas in North America. Our geographically concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative costs in addition to further leveraging our base of technical expertise in our project areas. We believe that offset operator activity and well results around our project areas have significantly de-risked our acreage positions such that we believe that there are low geologic risks and repeatable drilling opportunities across our acreage position.

Large, Multi-Year Inventory. We have an inventory of up to 898 gross (763 net) locations for potential future drilling on our Eagle Ford Shale acreage position and 60 gross (15 net) locations for potential future drilling on our Haynesville acreage position. For the period from January 2012 through December 2013, we plan on drilling 75 gross (46 net) wells on our Eagle Ford Shale acreage. The drilling and completion of these wells would represent approximately 8% of the total gross identified locations and approximately 6% of the total net identified locations on our Eagle Ford Shale acreage. As the industry continues to refine drilling and completion technologies, we may be able to enhance total recovery and inventory through the drilling of in-fill locations on our acreage positions. In addition, we have amassed approximately 82,000 net acres in Lewis and Clark, Meagher, and Cascade Counties of Montana that we believe may be prospective for the Heath, Three Forks and Bakken Shales. If we are successful in developing this acreage, we could materially expand our multi-year inventory.

Our Relationship with Members of the Sanchez Group and Our Services Agreement Provide Us with Extensive Technical Expertise and Access to Long Standing Relationships with Mineral Owners. Certain members of the Sanchez Group have been in the oil and natural gas business since 1972 and have drilled or participated in over 900 wells, directly and through joint ventures, in and around our South Texas and onshore Gulf Coast areas. This long operating history in the basins in which we operate provides us with extensive knowledge of the basins and the ability to leverage longstanding relationships with mineral owners. We believe that this expertise and these relationships, together with our services agreement, should allow us to develop our assets efficiently and increase our acreage position.

Significant Financial Flexibility. Following the completion of this offering and the other transactions described under Formation Transactions, we will have approximately $64 million in cash and no outstanding indebtedness. We will use this cash to fund our capital expenditures, and, in particular, our drilling, exploration and acquisition programs through December 2013, our other operating expenses, and for general corporate purposes. We currently expect that the net proceeds from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our available liquidity options.

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Eagle Ford Shale Well Results

In July 2011, we completed our first Maverick area Eagle Ford horizontal well, the Alpha Ware #1H, in Zavala County, Texas. This well was a 6,513 foot lateral well and was completed using a 20 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 242 bopd. Through October 10, 2011, the Alpha Ware #1H has produced a total of approximately 14,262 bo. We are the operator of the well and have a 60% working interest in the well.

In February 2011, we completed our fourth Eagle Ford horizontal well in our Palmetto area, the Barnhart #4H, in Gonzales County, Texas. This well was a 5,507 foot lateral well and was completed using a 16 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 893 boe/d (713 bopd and 1,080 mcf/d) using a 15/64 inch restricted choke. Through October 10, 2011, the Barnhart #4H has produced a total of approximately 153,066 boe (115,815 bo and 223,507 mcf). We have a 50% working interest in the well.

In November 2010, we completed our third Eagle Ford horizontal well in our Palmetto area, the Barnhart #3H, in Gonzales County, Texas. This well was a 5,320 foot lateral well and was completed using a 16 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 663 boe/d (618 bopd and 271 mcf/d) using a 15/64 inch restricted choke. Through October 10, 2011, the Barnhart #3H has produced a total of approximately 99,843 boe (94,510 bo and 31,995 mcf). We have a 50% working interest in the well.

In October 2010, we completed our second Eagle Ford horizontal well in our Palmetto area, the Barnhart #2H, in Gonzales County, Texas. This well was a 5,100 foot lateral well and was completed using a 12 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 1,102 boe/d (880 bopd and 1,330 mcf/d) using a 13/64 inch restricted choke. Through October 10, 2011, the Barnhart #2H has produced a total of approximately 153,268 boe (117,945 bo and 211,935 mcf). We have a 50% working interest in the well.

In July 2010, we completed our first Eagle Ford horizontal well in our Palmetto area, the Barnhart #1H, in Gonzales County, Texas. This well was a 3,902 foot lateral well and was completed using a 12 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 491 boe/d (447 bopd and 268 mcf/d) using a 17/64 inch restricted choke. Through October 10, 2011, the Barnhart #1H has produced a total of approximately 77,504 boe (66,856 bo and 63,886 mcf). We have a 50% working interest in the well.

Recent Developments

On November 8, 2011, we entered into a contribution agreement, or the Marquis Contribution Agreement, with Ross Exploration to acquire Marquis LLC, which owns a 100% working interest and an approximate 75% net revenue interest in approximately 54,900 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. We have agreed to pay Ross Exploration approximately $89 million in cash, subject to customary pre- and post-closing adjustments (and exclusive of certain costs and expenses for which we have agreed to reimburse Ross Exploration in cash at closing), and 909,091 shares of our common stock. The acreage that we are acquiring is subject to an overriding royalty interest that was previously conveyed by Ross Exploration to an affiliate as part of the transactions contemplated by the Marquis Contribution Agreement. Approximately 48,600 net acres are located in what we believe to be the volatile oil window of the Eagle Ford Shale in southwest Fayette and northeast Lavaca Counties, Texas. For the period from January 2012 through December 2013, we plan to spend approximately $135 million to drill 18 gross (18 net) wells in our Marquis area. See The Marquis Acquisition for additional information.

Since the end of the third quarter of 2011, we have drilled our fifth and sixth Eagle Ford Shale horizontal wells in our Palmetto area, the Barnhart #5H and #6H, in Gonzales County, Texas. We recently finished completion activities on these two wells and they commenced production in December 2011. The initial 24-hour production rates for the Barnhart #5H and #6H were 1,435 boe/d and 1,382 boe/d, respectively, using a 14/64 inch restricted choke.

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Our Principal Business Relationships

SEP I will be our largest stockholder following consummation of this offering and the other transactions described under Formation Transactions, holding approximately 66.9% of our post-offering outstanding common stock, assuming that the underwriters do not exercise their over-allotment option. SEP I was formed in late 2007 in order to facilitate the expansion of exploration activities previously begun in the early 2000 s by SOG and several independent parties to joint exploration agreements. SOG and the other parties contributed their assets to the newly formed SEP I and a second phase of equity fundraising was completed in early 2008. As a result, SOG and its affiliates became the largest limited partner in SEP I as well as its general partner. Collectively, SOG and its affiliates own approximately 24% of the limited partnership interests in SEP I. The unconventional assets acquired by SEP I are being contributed to us in exchange for cash and common stock in the transactions described under Formation Transactions.

Immediately following the consummation of this offering, SEP I will own a majority of our outstanding shares and, except for the lock-up period described under Underwriting and Conflicts of Interest, SEP I will not be subject to any contractual obligation to maintain its ownership in us. For more information on the potential effects of a disposition of our common stock by SEP I, please read Risk Factors Risks Relating to This Offering A substantial portion of our total outstanding shares may be sold into the market. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

Our Relationship with SOG and Other Members of the Sanchez Group

SOG, headquartered in Houston, Texas, is a private full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. SOG provides all the employee support to SEP I and other members of the Sanchez Group under the terms of a management services agreement and will provide similar services for us. SOG, as it is known today, had its beginnings in 1972, when A. R. Sanchez, Sr., A. R. Sanchez, Jr. and a group of other partners from Houston and Laredo, Texas, drilled their first well on the Hereford Ranch in Webb County, Texas. A.R. Sanchez Jr. is also the founder, Chief Executive Officer and Chairman of the Board of Directors of SOG. He has over 38 years of experience in the oil and natural gas industry and was involved in the discovery of several major oil and natural gas fields in Texas, including Bob West, Hereford, George West, Escobas, Highlands, La Sal Vieja, and Palmetto Eagle Ford fields. SOG s major areas of activity have been in the onshore Gulf Coast, Mid-Continent and Rocky Mountain regions. Since 1972, various members of the Sanchez Group have participated in and managed the drilling of over 900 wells, investing a substantial amount of capital in, among other things, well costs, seismic and acreage.

SOG has approximately 70 permanent employees and numerous contract professionals. These individuals are experienced energy professionals with expertise in finance and operations and broad technical skills in the oil and natural gas business. In connection with the ongoing business of SOG, its employees review a large number of potential acquisitions and are involved in decisions relating to the acquisition and disposition of oil and natural gas assets by the various portfolio companies in which SOG owns interests, including SEP I.

Although there is no obligation to do so, to the extent consistent with their fiduciary duties and other obligations to the investors and other parties associated with SOG, SOG and its affiliates may refer to us or allow us to participate in new acquisitions by its portfolio companies and may cause its portfolio companies to contribute or sell oil and natural gas assets to us in transactions that would be beneficial to all parties. Given this potential alignment of interests and the overlapping ownership of the management of SOG, SEP I and other members of the Sanchez Group and us, we believe that we will benefit from the collective expertise of the employees of SOG, their extensive network of industry relationships, and the access to potential acquisition opportunities that would not otherwise be available to us. For a summary of the process by which such mutually agreeable prices will be determined, please read Certain Relationships and Related Party Transactions Review, Approval or Ratification of Transactions with Related Persons.

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Risk Factors

An investment in our common stock involves a high degree of risk. You should consider and read carefully all of the risks and uncertainties described in Risk Factors beginning on page 19, together with all of the other information contained in this prospectus, including the financial statements and the related notes appearing at the end of this prospectus before deciding to invest in our common stock.

Formation Transactions

Immediately after the closing of this offering, the following transactions, which we refer to as the formation transactions, will occur:

- SEP I will contribute to us 100% of the limited liability company interests of SEP Holdings III, which owns interests in unconventional oil and natural gas assets consisting of undeveloped leasehold, proved oil and natural gas reserves and related equipment and other assets, referred to collectively herein as our properties.

- In exchange for the limited liability company interests described above and as further described in Use of Proceeds, we will pay SEP I $50 million from the proceeds of this offering and issue to SEP I 22,090,909 shares of our common stock.

- We will enter into a services agreement and other related agreements with SOG, pursuant to which SOG (directly or through its subsidiaries) will agree to provide us with the services and data that we believe are necessary to manage, operate and grow our business and we will agree to reimburse SOG for all direct and indirect costs incurred on our behalf.

- We will acquire 100% of the limited liability company interests of Marquis LLC, which owns approximately 54,900 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. In exchange for the limited liability company interests of Marquis LLC and as further described in Use of Proceeds, we will pay Ross Exploration approximately $89 million in cash, subject to adjustment, from the proceeds of the offering and issue to Ross Exploration 909,091 shares of our common stock. The acreage that we are acquiring is subject to an overriding royalty interest that was previously conveyed by Ross Exploration to an affiliate as part of the transactions contemplated by the Marquis Contribution Agreement.

To the extent the underwriters exercise their option to purchase up to an additional 1,500,000 shares of common stock from us, the number of shares of common stock issued to SEP I (as reflected in the second bullet above) will decrease by one-half of the aggregate number of shares of common stock purchased by the underwriters pursuant to such exercise and the number of shares of common stock issued to the public will increase by the aggregate number of shares of common stock purchased by the underwriters pursuant to such exercise. In addition, one-half of the net proceeds from any exercise of the underwriters option to purchase additional shares of common stock will be paid to SEP I. The number of shares of common stock SEP I is expected to hold after completion of this offering, assuming the underwriters do not exercise their option to purchase additional shares of common stock from us, is presented after giving effect to the issuance of 750,000 shares of common stock to SEP I at the expiration of the 30-day option period, unless otherwise indicated. This payment of net proceeds and/or issuance of shares of common stock to SEP I is intended to represent a portion of the consideration paid to SEP I for its contribution of all the limited liability company interests in SEP Holdings III to us.

For additional information, see Certain Relationships and Related Party Transactions and The Marquis Acquisition.

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Organizational Structure of Sanchez Energy Corporation

The diagram below illustrates our organizational structure based on total shares outstanding after giving effect to this offering and the related formation transactions and assumes that the underwriters do not exercise their over-allotment option to purchase additional shares.

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Principal Executive Offices and Internet Address

Our principal executive offices are located at 1111 Bagby Street, Suite 1600, Houston, Texas 77002. Our telephone number is (713) 783-8000. Our website is located at www.sanchezenergycorp.com. We expect to make available our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

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The Offering

Common stock offered by us	10,000,000 shares.
	11,500,000 shares, if the underwriters exercise their over-allotment option in full.
Common stock outstanding after this offering(1)(2)	33,000,000 shares (33,750,000 shares if the underwriters exercise their over-allotment option in full).
Use of proceeds	We will receive net proceeds of approximately $202.7 million from the sale of the common stock offered by us, after deducting estimated expenses and underwriting discounts and commissions of approximately $17.3 million. We intend to use $50 million of the net proceeds as partial consideration (together with our issuance to SEP I of 22,090,909 shares of our common stock) for the contribution by SEP I of the limited liability company interests in SEP Holdings III. We intend to use approximately $89 million of the net proceeds as partial consideration (together with the issuance to Ross Exploration of 909,091 shares of our common stock) for the acquisition of the limited liability company interests in Marquis LLC.
	We intend to use the remaining net proceeds of approximately $64 million and one-half of the net proceeds from the exercise of the underwriters option to purchase additional common stock from us to fund our capital expenditures, and, in particular, our drilling, exploration and acquisition programs through December 2013, our other operating expenses, and for general corporate purposes. The remaining one-half of the net proceeds from any exercise of the underwriters option to purchase additional shares of common stock will be paid to SEP I and the number of shares of common stock issued to SEP I will decrease by one-half the aggregate number of shares of common stock purchased by the underwriters pursuant to such exercise. See Use of Proceeds.
Dividend policy	We do not anticipate paying any cash dividends on our common stock. See Dividend Policy.
Risk factors	You should carefully read and consider the information beginning on page 19 of this prospectus set forth under the heading Risk Factors and all other information set forth in this prospectus before deciding to invest in our common stock.
Conflicts of interest	SEP I will use more than 5% of the net proceeds of this offering that it receives as part of the formation transactions to repay indebtedness owed by it to affiliates of the underwriters that are lenders under its credit agreement. See Use of Proceeds. Accordingly, this offering will be made in

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	compliance with the applicable provisions of Rule 5121 of the Financial Industry Regulatory Authority, Inc. This rule requires that a qualified independent underwriter meeting certain standards participate in the preparation of the registration statement and prospectus and exercise the usual standards of due diligence with respect thereto. Simmons & Company International has agreed to act as a qualified independent underwriter within the meaning of Rule 5121 in connection with this offering. See Underwriting and Conflicts of Interest Conflicts of Interest.
Exchange listing	Our common stock has been approved for listing on the New York Stock Exchange under the symbol SN.

(1) The number of shares of common stock to be outstanding after this offering excludes 3,960,000 shares of common stock expected to be reserved for issuance under our Long Term Incentive Plan. See Management Long Term Incentive Plan.

(2) If the underwriters do not exercise their option to purchase additional shares of common stock from us, we will issue 750,000 shares of common stock to SEP I at the expiration of the 30-day option period resulting in 33,000,000 shares of common stock outstanding after this offering. To the extent the underwriters partially exercise their option to purchase additional shares of common stock, the number of shares of common stock purchased by the underwriters pursuant to such exercise will be issued to the public and one-half of the remainder of the shares of common stock subject to the option, if any, will be issued to SEP I at the expiration of the 30-day option period.

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Summary Financial Data

The following table sets forth our summary financial data. The summary financial data as of December 31, 2009 and 2010 and for the years ended December 31, 2008, 2009 and 2010 are derived from our audited historical financial statements included elsewhere in this prospectus. The summary historical financial data as of September 30, 2011 and for the nine months ended September 30, 2010 and 2011 are derived from our unaudited historical financial statements included elsewhere in this prospectus. The results of operations for the interim periods are not necessarily indicative of operating results for the entire year or any future period.

Our historical financial statements have been prepared on a carve-out basis from the accounts of SEP I. These carve-out financial statements include all assets, liabilities and results of operations of the unconventional oil and natural gas properties and related assets to be contributed to us by SEP I for the periods presented.

You should read the following table in conjunction with Formation Transactions, Use of Proceeds, Selected Financial Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical financial statements and the notes thereto included elsewhere in this prospectus. Among other things, those historical financial statements include more detailed information regarding the basis of presentation for the following information.

The following table presents a non-GAAP financial measure, Adjusted EBITDA, which we use in evaluating the financial performance and liquidity of our business. This measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to the most directly comparable financial measures calculated and presented in accordance with GAAP.

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
				(Unaudited)	
			(in thousands)		
Statement of Operations Data:					
Total revenues	$ -	$ 241	$ 4,553	$ 1,465	$ 9,870
Total operating costs and expenses	$ 1,247	$ 196	$ 7,311	$ 4,584	$ 8,028
Operating income (loss)	$ (1,247)	$ 45	$ (2,758)	$ (3,119)	$ 1,842
Net income (loss)	$ (1,247)	$ 45	$ (2,758)	$ (3,119)	$ 3,400
Other Financial Data:					
Adjusted EBITDA	$ (1,247)	$ (1,612)	$ (1,328)	$ (2,794)	$ 4,607
Cash Flow Data:					
Net cash provided by (used in) operating activities	$ (1,247)	$ (1,710)	$ (3,777)	$ (3,140)	$ 2,198
Net cash provided by (used in) investing activities	$ (14,197)	$ 2,734	$ (7,925)	$ (9,101)	$ (10,917)
Net cash provided by (used in) financing activities	$ 15,444	$ (1,024)	$ 11,702	$ 12,240	$ 8,719

	As of December 31,		As of September 30, 2011	
	2009	2010	Historical	Pro Forma As Adjusted for This Offering
			(Unaudited)	
		(in thousands)		
Balance Sheet Data:				
Cash and cash equivalents	$ -	$ -	$ -	$ 64,285
Working capital (deficit)	$ 59	$ (1,818)	$ (379)	$ 64,060
Total assets	$ 13,275	$ 26,764	$ 39,681	$ 212,227
Parent net investment/stockholders equity	$ 13,218	$ 22,162	$ 34,719	$ 207,420

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Non-GAAP Financial Measures

We include in this prospectus the non-GAAP financial measure Adjusted EBITDA and provide reconciliations of Adjusted EBITDA to net income (loss) and net cash provided by (used in) operating activities, our most directly comparable financial performance and liquidity measures calculated and presented in accordance with GAAP. We define Adjusted EBITDA as net income (loss):

Plus:

- Interest expense, including realized and unrealized losses on interest rate derivative contracts;
- Income tax expense (benefit);
- Depreciation, depletion, and amortization;
- Accretion of asset retirement obligations;
- Loss (gain) on settlement of asset retirement obligations;
- Loss (gain) on sale of oil and natural gas properties;
- Unrealized losses on derivatives;
- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

Less:

- Interest income;
- Unrealized gains on derivatives; and
- Other non-recurring items that we deem appropriate.

Adjusted EBITDA will be used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

our operating performance as compared to that of other companies and partnerships in our industry, without regard to financing methods, capital structure or historical cost basis; and

our ability to incur and service debt and fund capital expenditures.

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Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following tables present our calculation of Adjusted EBITDA, a reconciliation of Adjusted EBITDA to net income (loss) and a reconciliation of Adjusted EBITDA to net cash provided by (used in) operating activities for each of the periods indicated.

Calculation of and Reconciliation of Net Income (Loss) to Adjusted EBITDA

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
			(in thousands)		
Net income (loss)	$ (1,247)	$ 45	$ (2,758)	$ (3,119)	$ 3,400
Depreciation, depletion, and amortization	-	415	1,428	324	2,761
Accretion of asset retirement obligations	-	0	2	1	4
Unrealized gain on derivatives	-	-	-	-	(1,558)
Gain on sale of oil and natural gas properties	-	(2,686)	-	-	-
Impairment of properties	-	614	-	-	-
Adjusted EBITDA	$ (1,247)	$ (1,612)	$ (1,328)	$ (2,794)	$ 4,607

Reconciliation of Net Cash Provided by (Used in) Operating Activities to Adjusted EBITDA

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
			(in thousands)		
Net cash provided by (used in) operating activities	$ (1,247)	$ (1,710)	$ (3,777)	$ (3,140)	$ 2,198
Net change in operating assets and liabilities	-	98	2,449	346	2,409
Adjusted EBITDA	$ (1,247)	$ (1,612)	$ (1,328)	$ (2,794)	$ 4,607

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Summary Reserve and Operating Data

The following tables present summary data with respect to our estimated net proved oil and natural gas reserves as of June 30, 2011, which is based on a report that has been prepared by Ryder Scott. These reserve estimates were prepared in accordance with the SEC s rules regarding oil and natural gas reserve reporting that are currently in effect. The following tables also contain certain summary information regarding production and operating data with respect to such properties for the periods presented. For further information regarding the calculation of the standardized measure (and the effect of income taxes), see Unaudited Supplementary Information included in the financial statements elsewhere in this prospectus.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and Properties Oil and Natural Gas Reserves and Production, and Risk Factors in evaluating the material presented below.

	As of June 30, 2011 (Unaudited)
Estimated Proved Reserves	
Oil (mbo)	2,596.1
Natural gas (mmcf)	3,889.3
Total (mboe)(1)	3,244.3
Proved developed (mboe)	646.9
Proved undeveloped (mboe)	2,597.5
Proved developed reserves as a percentage of total proved reserves	19.9%
Standardized measure (in millions)(2)	$ 69.5
Oil and Natural Gas Prices(3)	
Oil NYMEX WTI per bo	$ 90.09
Natural gas NYMEX Henry Hub per mmbtu	$ 4.21

(1) One boe is equal to six mcf of natural gas or one bo of oil or natural gas liquids, or NGLs, based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(2) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC without giving effect to non-property related expenses, such as general and administrative expenses, interest expense, or to depletion, depreciation and amortization. The future cash flows are discounted using an annual discount rate of 10%. Standardized measure does not give effect to derivative transactions. We expect to hedge a portion of our future estimated production from total proved reserves. Prior to the closing of this offering, we will not be treated as a taxable entity for federal income tax purposes. Future calculation of the standardized measure will include the effects of income taxes on future net revenues. For further discussion of income taxes, see Management s Discussion and Analysis of Financial Condition and Results of Operations.

(3) Our estimated net proved reserves and related standardized measure were determined using average index prices for oil and natural gas, without giving effect to derivative contracts, held constant throughout the life of our properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $90.09/bo for oil and $4.21/mmbtu for natural gas at June 30, 2011. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead.

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	Year Ended December 31, 2010	Nine Months Ended September 30, 2010	2011
		(Unaudited)	
Net Production:			
Total production (mboe)	61.1	20.5	117.7
Average daily production (boe/d)	167.4	75.0	431.1
Average Realized Sales Price:			
Oil (mbo)	$ 78.92	$ 71.55	$ 92.31
Natural gas (mmcf)	$ 4.68	$ -	$ 4.69
Average Realized Sales Price per boe[(1)]:	$ 74.50	$ 71.55	$ 83.85
Average Unit Costs per boe:			
Oil and natural gas production expenses	$ 6.41	$ 3.44	$ 10.27
Production and ad valorem taxes	$ 3.50	$ 3.30	$ 4.68
General and administrative	$ 86.32	$ 201.29	$ 29.77
Depletion, depreciation and amortization	$ 23.36	$ 15.80	$ 23.46

(1) Amounts shown are based on oil and natural gas sales. We did not have any realized commodity derivative gains (losses) as of the dates presented.

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RISK FACTORS

An investment in our common stock involves a high degree of risk. You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this prospectus, including the financial statements and the related notes appearing at the end of this prospectus before deciding to invest in our common stock. If any of the following risks actually occurs, our business, business prospects, financial condition, results of operations or cash flows could be materially adversely affected. In any such case, the trading price of our common stock could decline, and you could lose all or part of your investment. The risks below are not the only ones facing our company. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This prospectus also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below.

Risks Related to Our Business

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in estimated reserves, estimated drilling costs or underlying assumptions will materially affect our business.

Exploring for and developing oil and natural gas reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploratory wells bear a much greater risk of loss than development wells. Moreover, the successful drilling of an oil or natural gas well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomic or only marginally economic. Our initial drilling locations, and any potential additional locations that may be developed, require significant additional exploration and development, regulatory approval and commitments of resources prior to commercial development. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

Our estimated oil and natural gas reserves will naturally decline over time, and we may be unable to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations.

Our future oil and natural gas reserves, production volumes, and cash flow depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. Our estimated oil and natural gas reserves will naturally decline over time as they are produced. Our success depends on our ability to economically develop, find or acquire additional reserves to replace our own current and future production. If we are unable to do so, or if expected development is delayed, reduced or cancelled, the average decline rates will likely increase.

Developing and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

The cost of developing, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a well. Our efforts will be uneconomical if we drill dry holes or wells that are productive but do not produce as much oil and natural gas as we had estimated. Furthermore, our development and production operations may be curtailed, delayed or canceled as a result of other factors, including:

- high costs, shortages or delivery delays of rigs, equipment, labor or other services;

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composition of sour gas, including sulfur and mercaptan content;

unexpected operational events and conditions;

reductions in oil and natural gas prices;

increases in severance taxes;

adverse weather conditions and natural disasters;

facility or equipment malfunctions and equipment failures or accidents, including acceleration of deterioration of our facilities and equipment due to the highly corrosive nature of sour gas;

title problems;

pipe or cement failures, casing collapses or other downhole failures;

compliance with ever-changing environmental and other governmental requirements;

environmental hazards, such as natural gas leaks, oil spills, salt water spills, pipeline ruptures and discharges of toxic gases;

lost or damaged oilfield development and service tools;

unusual or unexpected geological formations and pressure or irregularities in formations;

loss of drilling fluid circulation;

fires, blowouts, surface craterings and explosions;

uncontrollable flows of oil, natural gas or well fluids;

loss of leases due to incorrect payment of royalties; and other hazards, including those associated with sour gas such as an accidental discharge of hydrogen sulfide gas, that could also result in personal injury and loss of life, pollution and suspension of operations.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our business, financial condition and results of operations.

We routinely apply hydraulic fracturing techniques in many of our drilling and completion operations. Hydraulic fracturing has recently become subject to increased public scrutiny and recent changes in federal and state law, as well as proposed legislative changes, could significantly restrict the use of hydraulic fracturing. Such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, such laws could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. If hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the U.S. Environmental Protection Agency, or the EPA, or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays, financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, as well as potential increases in costs. Additionally, on August 23, 2011, the EPA published a proposed rule in the Federal Register that would establish new air emission controls for oil and natural gas production and natural gas processing operations. The EPA is currently receiving public comment and recently conducted public hearings regarding the proposed rules and must take final action on them by February 28, 2012. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. In addition, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation. Please read Risks Related to our Business Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays and Business and Properties Environmental Matters and Regulations Water and Other Water Discharges and Spills.

Additionally, hydraulic fracturing, drilling, transportation and processing of hydrocarbons bear an inherent risk of loss of containment. Potential consequences include loss of reserves, loss of production, loss of economic value associated with the affected wellbore, contamination of soil, ground water, and surface water, as well as potential fines, penalties or damages associated with any of the foregoing consequences.

Our acquisition, development and production operations will require substantial capital expenditures, and we expect to fund these capital expenditures using cash generated from our operations or the issuance of debt and equity securities, or some combination thereof. Our failure to obtain the funds for necessary future growth capital expenditures could have a material adverse effect on our business, financial condition and results of operations.

The oil and natural gas industry is capital intensive. We expect to make substantial growth capital expenditures in our business for the acquisition, development and production of oil and natural gas reserves. We intend to finance our future growth and capital expenditures with cash flows from operations and the issuance of debt and equity securities, or some combination thereof.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- our estimated proved oil and natural gas reserves;
- the amount of oil, natural gas and NGLs we produce;
- the prices at which we sell our production;
- the costs of developing, producing, and transporting our oil and natural gas assets, including costs attributable to governmental regulation and taxation;
- our ability to acquire, locate and produce new reserves;
- fluctuations in our working capital needs;
- interest payments and debt service requirements;
- prevailing economic conditions;

- the ability and willingness of banks and other lenders to lend to us; and

- our ability to access the equity and debt capital markets.

If additional capital is needed to fund our growth capital expenditures, our ability to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering, as well as by adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control.

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A decline in oil, natural gas or NGLs prices will cause a decline in our cash flow from operations, which could adversely affect our business, financial condition and results of operations.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and foreign supply of and demand for oil and natural gas;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries globally, including terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war;
- actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state-controlled oil companies relating to oil price and production controls;
- the effect of increasing liquefied natural gas deliveries to and exports from the United States;
- the impact of the U.S. dollar exchange rates on oil and natural gas prices;
- technological advances affecting energy supply and energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost and availability of oil and natural gas pipelines and other transportation facilities;
- the availability of refining capacity; and
- the price and availability of alternative fuels.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, for the five years ended December 31, 2010, the NYMEX WTI oil price ranged from a high of $145.29 per bbl to a low of $31.41 per bo, while the NYMEX Henry Hub natural gas price ranged from a high of $13.31 per mmbtu to a low of $1.83 per mmbtu. Such volatility may affect the amount of our net estimated proved reserves and will affect the standardized measure of discounted future net cash flows of our net estimated proved reserves.

Natural gas prices are closely linked to the supply of natural gas and consumption patterns in the United States of the electric power generation industry and certain industrial and residential users where natural gas is the principal fuel. The domestic natural gas industry continues to face concerns of oversupply due to the success of new trends and continued drilling in these trends, despite lower natural gas prices.

Our revenue, profitability and cash flow depend upon the prices of and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

- limit our ability to enter into commodity derivative contracts at attractive prices;

- reduce the value and quantities of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can economically produce;

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- reduce the amount of cash flow available for capital expenditures; and

- limit our ability to borrow money or raise additional capital.

An increase in the differential between the NYMEX or other benchmark prices of oil and natural gas and the wellhead price we receive for our production could adversely affect our business, financial condition and results of operations.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark price and the price we receive is called a basis differential. Increases in the basis differential between the benchmark prices for oil and natural gas and the wellhead price we receive could adversely affect our business, financial condition and results of operations. We do not have or currently plan to have any commodity derivative contracts covering the amount of the basis differentials we experience in respect of our production. As such, we will be exposed to any increase in such differentials, which could adversely affect our business, financial condition and results of operations.

SEP I will contribute to us at the closing of this offering a commodity derivative contract with a deferred premium cost of approximately $1.9 million, and, in the future, we expect to enter into commodity derivative contracts for a portion of our estimated production from total estimated proved developed producing reserves that could result in both realized and unrealized hedging losses. We also expect to adopt a hedging policy designed to reduce the impact to our cash flows from commodity price volatility. Our hedging strategy and future hedging transactions will be determined by our management, which is not under any obligation to enter into commodity derivative contracts covering any specific portion of our production.

The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices at the time we enter into these transactions, which may be substantially higher or lower than past or current oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices realized for our future production. Conversely, our hedging strategy may limit our ability to realize incremental cash flows from commodity price increases. As such, our hedging strategy may not protect us from changes in oil and natural gas prices that could have a significant adverse effect on our liquidity, business, financial condition and results of operation.

Economic uncertainty could negatively impact the prices for oil and natural gas, limit our access to the debt and equity markets, increase our cost of capital, and may have other negative consequences that we cannot predict.

Economic uncertainty in the United States could create financial challenges if conditions do not improve. Most recently, Standard & Poor s downgraded the U.S. credit rating to AA+ from its top rank of AAA, which has increased the possibility of other credit-rating agency downgrades which could have a material adverse effect on the financial markets and economic conditions in the United States and throughout the world. Our ability to access capital may be restricted at a time when we would like, or need, to raise capital. If our cash flow from operations is less than anticipated and our access to capital is restricted, we may be required to reduce our operating and capital budget, which could have a material adverse effect on our business, financial condition and results of operations. Ongoing uncertainty may also reduce the values we are able to realize in asset sales or other transactions we may engage in to raise capital, thus making these transactions more difficult and less economic to consummate. Additionally, demand for oil and natural gas may deteriorate and result in lower prices for oil and natural gas, which could have a negative impact on our business, financial condition and results of operations. Lower prices could also adversely affect the collectability of our trade receivables and cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations.

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We are increasing production in areas of high industry activity, which may impact our ability to obtain the personnel, equipment, services, resources and facilities access needed to complete our development activities as planned or result in increased costs.

Our strategy is to expand drilling activity in areas in which industry activity has increased rapidly, particularly in the Eagle Ford Shale trend in South Texas. As a result, demand for personnel, equipment, hydraulic fracturing, water and other services and resources, as well as access to transportation, processing and refining facilities in these areas has increased, as has the costs for those items. A delay or inability to secure the personnel, equipment, services, resources and facilities access necessary for us to complete our development activities as planned could result in a rate of oil and natural gas production below the rate forecasted, and significant increases in costs would impact our profitability.

Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices and activity levels in new regions, causing periodic shortages. During periods of high oil and natural gas prices, SOG has experienced shortages of equipment, including drilling rigs and completion equipment, as demand for rigs and equipment has increased along with higher commodity prices and increased activity levels. In addition, there is currently a shortage of hydraulic fracturing capacity in many of the areas in which we operate. Higher oil and natural gas prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services and personnel in our exploration and production operations. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those operations that we currently have planned and budgeted, causing us to miss our forecasts and projections.

If we do not purchase additional acreage or make acquisitions on economically acceptable terms, our future growth will be limited.

Our ability to grow depends in part on our ability to make acquisitions on economically acceptable terms. We may be unable to make such acquisitions because we are:

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

If we are unable to acquire properties containing estimated proved reserves, our total level of estimated proved reserves will decline as a result of our production.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage or the leases are extended.

Certain of our undeveloped leasehold acreage is subject to leases that will expire unless production in paying quantities is established during their primary terms or we obtain extensions of the leases. Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we do not know if our undeveloped leasehold acreage will ever be drilled or if we will be able to produce crude oil or natural gas from these or any other potential drilling locations. If our leases expire, we will lose our right to develop the related properties on this acreage. Excluding the properties to be acquired in the Marquis acquisition, as of September 30, 2011, we had leases representing 1,454 net acres (1,369 of which were in the Eagle Ford Shale) expiring in 2011, 4,988 net acres (4,837 of which were in the Eagle Ford Shale) expiring in 2012, and 21,259 net acres (21,214 of which were in the Eagle Ford Shale) expiring in 2013. The Marquis acquisition includes approximately 54,900 net acres, none of which expires before December 31, 2013 except: (i) leases comprising 1,739 net acres covering properties in Webb County, Texas (with respect to each of which the lessee has an optional right to extend the primary term for a two-year period); (ii) properties comprising 695 net acres covering properties in DeWitt County, Texas; and (iii) properties comprising 461 net acres covering properties in Fayette County, Texas. In addition, we will have the option to acquire additional properties acquired by Ross Exploration in the Marquis acquisition under certain circumstances. See The Marquis Acquisition. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

Availability of adequate gathering systems and transportation take-away capacity may hinder our access to suitable oil and natural gas markets or delay our production.

Our ability to bring oil, natural gas and NGLs production to market depends on a number of factors including the availability and proximity of pipelines and processing facilities. The recent growth in production in the Eagle Ford Shale, especially of natural gas and NGLs production, has limited the availability of transportation take-away capacity for these products in certain parts of this trend. If we are unable to obtain adequate amounts of take-away capacity to meet our growing production levels, we may have to delay initial production or shut in our wells awaiting a pipeline connection or capacity or sell our production at significantly lower prices than those quoted on NYMEX or than we currently project, which could adversely affect our business, financial condition and results of operations.

We have drilled only seven wells in the Eagle Ford Shale, we are not the operator of our wells in the Haynesville Shale and we have not drilled wells in the Heath, Three Forks and Bakken Shales, and thus we have limited information regarding reserves and decline rates in the Eagle Ford Shale, Haynesville Shale, and the Heath, Three Forks and Bakken Shales. Wells drilled in these shale areas are more expensive and more susceptible to mechanical problems in drilling and completion techniques than wells in conventional areas.

We have drilled only seven wells in the Eagle Ford Shale, we are not the operator of our wells in the Haynesville Shale and we have not drilled wells in the Heath, Three Forks and Bakken Shales. Other operators in the Eagle Ford Shale, Haynesville Shale, and the Heath, Three Forks and Bakken Shales have significantly more experience in the drilling and completion of these wells, including the drilling and completion of horizontal wells. In addition, we have limited information with respect to the ultimate recoverable reserves and production decline rates in these areas. The wells drilled in the Eagle Ford Shale, Haynesville Shale, and the Heath, Three Forks and Bakken Shales are primarily horizontal and require more stimulation, which makes them more expensive to drill and complete. The wells will also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore due to the length of the lateral portions of these unconventional wells. The fracturing of these shale formations will be more extensive and complicated than fracturing geological formations in conventional areas of operation.

Our hedging transactions could result in cash losses, limit potential gains and materially impact our liquidity.

Many of the derivative contracts to which we may be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity, business, financial condition and results of operations.

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Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is a process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate natural gas and, to a lesser extent, oil production. This process is typically regulated by state agencies. The EPA, however, recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act s, or SDWA, Underground Injection Control, or UIC, Program by posting a new requirement on its website that requires facilities to obtain permits to use diesel fuel in hydraulic fracturing operations. The U.S. Energy Policy Act of 2005, which exempts hydraulic fracturing from regulation under the SDWA, prohibits the use of diesel fuel in the fracturing process without a UIC permit. Although the EPA has yet to take any action to enforce or implement this newly-asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decisions as a final agency action and, thus, violative of the notice-and-comment rulemaking procedures of the Administrative Procedures Act. At the same time, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives also has commenced its own investigation into hydraulic fracturing practices. Additionally, legislation has been introduced in the U.S. Congress to amend the SDWA to subject hydraulic fracturing processes to regulation under that Act and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Further, certain members of the Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Finally, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board released a report on August 11, 2011, proposing recommendations to reduce the potential environmental impacts from shale gas production. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism. Also, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances or otherwise require the public disclosure of chemicals used in the hydraulic fracturing process. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic fracturing process. Furthermore, in July 2011, the EPA proposed several new emissions standards to reduce volatile organic compound, or VOC, emissions from several types of processes and equipment used in the oil and natural gas industry, including a 95 percent reduction in VOCs emitted during the construction or modification of hydraulically-fractured wells. Additionally, on August 23, 2011, the EPA published a proposed rule in the Federal Register that would establish new air emission controls for oil and natural gas production and natural gas processing operations. The EPA is currently receiving public comment and recently conducted public hearings regarding the proposed rules and must take final action on them by February 28, 2012. If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to drill and produce from conventional or tight formations, increase our costs of compliance and doing business and make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings. In addition, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation.

If hydraulic fracturing is regulated at the federal level, fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased

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monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of failure to comply by us could have a material adverse effect on our business, financial condition and results of operations. At this time, it is not possible to estimate the potential impact on our business that may arise if federal or state legislation governing hydraulic fracturing is enacted into law.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden changes in a counterparty s liquidity, which could impair its ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty s creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

Our estimated reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

Numerous uncertainties are inherent in estimating quantities of oil and natural gas reserves and future production. It is not possible to measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering is complex, requiring subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels and operating and development costs. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- the level of oil, natural gas and NGL prices;
- future production levels;
- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and
- the availability of funds.

If these assumptions prove to be incorrect, our estimates of our reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our estimated reserves could change significantly. Moreover, the variability is likely to be higher for probable and possible reserve estimates. For example, if the prices used in our reserve report as of June 30, 2011 had been $10.00 less per bo and $1.00 less per mmbtu for natural gas, then the standardized measure of our estimated proved reserves as of that date would have decreased by approximately $17.6 million, from approximately $69.5 million to approximately $51.9 million.

Our standardized measure is calculated using unhedged oil, natural gas and NGL prices and is determined in accordance with the rules and regulations of the SEC. Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual development and production.

The reserve estimates we make for wells or fields that do not have a lengthy production history are less reliable than estimates for wells or fields with lengthy production histories. A lack of production history may contribute to inaccuracy in our estimates of proved reserves, future production rates and the timing of development expenditures.

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Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our prospects are in various stages of evaluation. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies, and the study of producing fields in the same area, will not enable us to know conclusively before drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercially viable quantities. Moreover, the analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

The present value of future net revenues from our estimated reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves.

The present value of future net revenues from our estimated reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our estimated reserves on prices and costs in effect as of the date of the estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the actual prices we receive for oil, natural gas and NGLs;
- our actual operating costs in producing oil, natural gas and NGLs;
- the amount and timing of actual production;
- the amount and timing of our capital expenditures;
- the supply of and demand for oil, natural gas and NGLs; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from our estimated reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with Accounting Standards Codification 932, Extractive Activities Oil and Natural Gas, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

We may experience a financial loss if SOG is unable to sell a significant portion of our oil and natural gas production.

Under our services agreement, SOG will sell our oil, natural gas and NGL production on our behalf. SOG s ability to sell our production depends upon market conditions and the demand for oil, natural gas and NGLs from SOG s customers.

In recent years, a number of energy marketing and trading companies have discontinued their marketing and trading operations, which has significantly reduced the number of potential purchasers for our production. This reduction in potential customers has reduced overall market liquidity. If any one or more of our significant customers reduces the volume of oil and natural gas production it purchases and SOG is unable to sell those volumes to other customers, then the volume of our production that SOG sells on our behalf could be reduced, which could have an adverse affect on our business, financial condition and results of operations.

In addition, a failure by any of these companies, or any purchasers of our production, to perform their payment obligations to us could have a material adverse effect on our business, financial condition and results of operations. To the extent that purchasers of our production rely on access to the debt or equity markets to fund

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their operations, there could be an increased risk that those purchasers could default in their contractual obligations to us. If for any reason we were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of our production were uncollectible, we would recognize a charge to our earnings in that period for the probable loss and could suffer a material reduction in our liquidity.

Lower oil and natural gas prices may cause us to record ceiling limitation impairments, which would reduce our stockholders equity.

We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Under full cost accounting rules, the net capitalized cost of oil and natural gas properties may not exceed a ceiling limit that is based upon the present value of estimated future net revenues from net proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties and other adjustments as required by Regulation S-X under the Securities Act. If net capitalized costs of oil and natural gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a ceiling limitation impairment. The risk that we will experience a ceiling limitation impairment increases when oil and natural gas prices are depressed, if we have substantial downward revisions in estimated net proved reserves or if estimates of future development costs increase significantly. No assurance can be given that we will not experience a ceiling limitation impairment in future periods.

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

Our management has specifically identified and scheduled drilling locations as an estimation of our future drilling activities on our existing acreage through December 2013. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

Any acquisitions we complete or geographic expansions we undertake will be subject to substantial risks that could have a negative impact on our business, financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs, including synergies;
- an inability to successfully integrate the assets or businesses we acquire;
- a decrease in our liquidity by using a significant portion of our cash and cash equivalents to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- the diversion of management s attention from other business concerns;

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- mistaken assumptions about the overall cost of equity or debt;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- facts and circumstances that could give rise to significant cash and certain non-cash charges; and
- customer or key employee losses at the acquired businesses.

Further, we may in the future expand our operations into new geographic areas with operating conditions and a regulatory environment that may not be as familiar to us as our existing project areas. As a result, we may encounter obstacles that may cause us not to achieve the expected results of any such acquisitions, and any adverse conditions, regulations or developments related to any assets acquired in new geographic areas may have a negative impact on our business, financial condition and results of operations.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations. Our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition, given time constraints imposed by sellers. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate revenue.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and properties, marketing oil and natural gas, and securing equipment and trained personnel. Many of our competitors are large independent oil and natural gas companies that possess and employ financial, technical and personnel resources substantially greater than those of the Sanchez Group. Those entities may be able to develop and acquire more properties than our financial or personnel resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business, financial condition and results of operations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in our wells and other operating properties and facilities, such as leaks, explosions, mechanical problems and natural disasters, all of which could cause substantial financial losses. Any of these or other similar occurrences could result in the disruption of our operations,

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substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses. The location of our wells and other operating properties and facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs or on commercially reasonable terms. Changes in the insurance markets due to weather, adverse economic conditions, and the aftermath of the Macondo well incident in the Gulf of Mexico have made it more difficult for us to obtain certain types of coverage. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and we cannot be sure the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition and results of operations.

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. Insurance may be inadequate, and in some instances, we may not be able to obtain insurance on commercially reasonable terms, or insurance might not be available at all. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, financial condition and results of operations.

Our customers energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in some of the areas where we operate are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our properties are located in regions which make us vulnerable to risks associated with operating in one major contiguous geographic area, including the risk and related costs of damage or business interruptions from hurricanes.

Our properties are primarily located in the Eagle Ford Shale in South Texas, and as a result of this geographic concentration, we are disproportionately affected by any delays or interruptions in production or transportation in these areas caused by governmental regulation, transportation capacity constraints, natural disasters, regional price fluctuations and other factors. Such disturbances have in the past and will in the future have any or all of the following adverse effects on our business:

- interruptions to our operations as we suspend production in advance of an approaching storm;

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- damage to our facilities and equipment, including damage that disrupts or delays our production;
- disruption to the transportation systems we rely upon to deliver our products to our customers; and
- damage to or disruption of our customers facilities that prevents us from taking delivery of our products.

Although we maintain property and casualty insurance, we cannot predict whether we will continue to be able to obtain insurance for hurricane-related damages or, if obtainable and carried, whether this insurance will be adequate to cover our losses. In addition, we expect any insurance of this nature to be subject to substantial deductibles and to provide for premium adjustments based on claims. Any future hurricane-related costs and work interruptions could adversely affect our business, financial condition and results of operations.

Our lack of diversification will increase the risk of an investment in us.

Our current business focus is on the oil and natural gas industry in a limited number of properties, primarily in the Eagle Ford Shale in South Texas. Larger companies have the ability to manage their risk by diversification. However, we currently lack diversification, in terms of both the nature and geographic scope of our business. As a result, we will likely be impacted more acutely by factors affecting our industry or the regions in which we operate than we would if our business were more diversified, increasing our risk profile.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate all of the properties in which we own an ownership interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these non-operated properties. The failure of an operator of our wells to adequately perform operations, an operator s breach of the applicable agreements or an operator s failure to act in ways that are in our best interests could reduce our production, revenues and reserves. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of the operator s drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator s geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator s selection of suitable technology.

Our historical financial information may not be representative of the results we would have achieved as a stand-alone public company and may not be a reliable indicator of our future results.

The historical financial information that we have included in this prospectus has been prepared on a carve-out basis from the accounts of SEP I and may not necessarily reflect what our financial position, results of operations or cash flows would have been had we been an independent, stand-alone entity during the periods presented or those that we will achieve in the future. SEP I did not account for us, and we were not operated, as a separate, stand-alone company for the historical periods presented. The costs and expenses reflected in our historical financial information include allocations of general and administrative expenses for employee, management, and administrative support provided by SOG to SEP I. These allocations were primarily based on the ratio of capital expenditures between the entities to which SOG provides services and us, and also on other factors, such as time spent on general management services and producing property activities. Although SOG will continue to provide these services to us pursuant to a services agreement and management believes such allocations are reasonable, such allocations may not be indicative of the actual expense that would have been

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incurred had we been an independent, stand-alone entity during the periods presented. In addition, we have not adjusted our historical financial information to reflect changes that will occur in our cost structure and operations as a result of our transition to becoming a stand-alone public company, including potential increased costs associated with reduced economies of scale and increased costs associated with the SEC reporting and the New York Stock Exchange, or the NYSE, requirements. Therefore, our historical financial information may not necessarily be indicative of what our financial position, results of operations or cash flows will be in the future. For additional information, see Selected Financial Data and Management s Discussion and Analysis of Financial Condition and Results of Operations, and our financial statements and related notes included elsewhere in this prospectus.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas development and production operations are subject to complex and stringent laws and regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and production and processing of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. Please read Business and Properties Environmental Matters and Regulation and Business and Properties Other Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

On April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts, et al. v. EPA, that the federal Clean Air Act definition of pollutant includes carbon dioxide and other greenhouse gases, or GHGs, and, therefore, the EPA has the authority to regulate carbon dioxide emissions from automobiles. Thereafter, on December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA subsequently adopted two sets of regulations under the existing Clean Air Act, one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain stationary sources to obtain permits and employ technologies to reduce GHG emissions. The EPA published the motor vehicle final rule in May 2010 and it became effective January 2011 and applies to vehicles manufactured in model years 2012-2016. The EPA adopted the stationary source rule in May 2010, and it also became effective January 2011, applying first to the largest emitters of GHGs and providing the potential for application to smaller emitters in later years. Both rules remain the subject of several lawsuits filed by industry groups in the U.S. Court of Appeals for the District of Columbia Circuit. Additionally, the EPA requires reporting of GHG emissions from certain emission sources. In October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. Furthermore, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. The final rule, which may be applicable to many of our facilities, will require reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. The EPA also plans to implement GHG emissions standards for power plants in May 2012 and for refineries in November 2012.

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In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security, or ACES, Act that, among other things, would have established a cap-and-trade system to regulate GHG emissions and would have required an 80% reduction in GHG emissions from sources within the United States between 2012 and 2050. The ACES Act did not pass the Senate, however, and so was not enacted by the 111th Congress. The United States Congress is likely to consider again a climate change bill in the future. In addition, almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. Furthermore, some states have enacted renewable portfolio standards, which require utilities to purchase a certain percentage of their energy from renewable fuel sources. The adoption of any legislation or regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur increased operating costs, such as costs to monitor and report GHG emissions, purchase and operate emissions control systems to reduce emissions of GHGs associated with our operations, acquire emissions allowances or comply with new regulatory requirements. Any GHG emissions legislation or regulatory programs applicable to power plants or refineries could also increase the cost of consuming, and thus could adversely affect demand for the oil and natural gas that we produce. Consequently, legislation and regulatory programs to reduce GHG emissions could have an adverse effect on our business, financial condition and results of operations. Please read Business and Properties Environmental Matters and Regulation.

Our operations are subject to environmental and operational safety laws and regulations that may expose us to significant costs and liabilities.

We may incur significant delays, costs and liabilities as a result of stringent and complex environmental, health and safety requirements applicable to our oil and natural gas development and production operations. These laws and regulations may impose numerous obligations applicable to our operations, including that they may (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling, production and transportation activities; (iii) govern the sourcing and disposal of water used in the drilling and completion process; (iv) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (v) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; (vi) result in the suspension or revocation of necessary permits, licenses and authorizations; (vii) impose substantial liabilities for pollution resulting from drilling and production operations; and (viii) require that additional pollution controls be installed. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly compliance or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations and limit our growth and revenue. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination

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regardless of whether we were responsible for the release or contamination or the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition and results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our competitive position, business, financial condition and results of operations. We may not be able to recover some or any of these costs from insurance. Please read Business and Properties Environmental Matters and Regulation for more information.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations. Please read Business and Properties Environmental Matters and Regulation and Business and Properties Other Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect the third parties on whom we rely.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. In October 2011, the Commodities Futures Trading Commission, or the CFTC, approved final rules that establish position limits for futures contracts on 28 physical commodities, including four energy commodities, and swaps, futures that are economically equivalent to those contracts. The rules provide an exemption for bona fide hedging transactions or positions, but this exemption is narrower than the exemption under existing CFTC position limit rules. The new limits generally will go into effect 60 days after the CFTC further defines the term swap . The financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative contracts to spin off some of their derivatives contracts to a separate entity, which may not be as creditworthy as the current counterparty. The regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

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Our ability to produce oil and natural gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. The Clean Water Act imposes restrictions and strict controls regarding the discharge of produced waters and other oil and natural gas waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The Clean Water Act and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations, and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into coastal waters. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Indeed, on October 20, 2011, the EPA announced its intention to develop federal pre-treatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the new pretreatment rules will require coalbed methane and shale gas operations to pretreat wastewater before transferring it to treatment facilities. Proposed rules are expected in 2013 for coalbed methane and 2014 for shale gas. We cannot predict the impact that these standards may have on our business at this time, but these standards could have a material impact on our business, financial condition and results of operation. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

Because we are a relatively small company, the requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended, and the requirements of the Sarbanes-Oxley Act may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

We have no history operating as a publicly-traded company. As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, including the reporting obligations of the Securities Exchange Act of 1934, as amended, or the Exchange Act, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time from our board of directors and management and will significantly increase our legal and financial compliance costs and make such compliance more time-consuming and costly. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

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establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;

involve and retain to a greater degree outside counsel and accountants in the above activities; and

establish an investor relations function.

In addition, we also expect that being a public company subject to these rules and regulations will make it more difficult and expensive for us to obtain director and officer liability insurance and we may be required to accept greater coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified executive officers and qualified members to serve on our board of directors, particularly the audit committee of the board of directors.

We are not currently required to comply with the SEC s rules implementing Section 404 of the Sarbanes-Oxley Act of 2002 and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. We will not be required to make our first assessment of our internal control over financial reporting until the year following our first annual report required to be filed with the SEC. To comply with the requirements of being a public company, we will need to upgrade our systems, including information technology, implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance and legal staff.

Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act of 2002. Further, our remediation efforts may not enable us to remedy or avoid material weaknesses or significant deficiencies in the future. Any failure to remediate material weaknesses or significant deficiencies and to develop or maintain effective controls, or any difficulties encountered in our implementation or improvement of our internal controls over financial reporting could result in material misstatements that are not prevented or detected on a timely basis, which could potentially subject us to sanctions or investigations by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information.

We may incur more taxes and certain of our projects may become uneconomic if certain federal income tax deductions currently available with respect to oil and natural gas exploration and production are eliminated as a result of future legislation.

The President s proposed budget for fiscal year 2012 and his proposed American Jobs Act of 2011 contain proposals to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any of the foregoing changes will actually be enacted or how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate and/or defer certain tax deductions that are currently available with respect to oil and natural gas exploration and production. Any such change could materially adversely affect our business, financial condition and results of operations by increasing the after-tax costs we incur which would in turn make it uneconomic to drill some locations if commodity prices are not sufficiently high, resulting in lower revenues and decreases in production and reserves.

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Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

We rely on SOG for certain services necessary for us to be able to conduct our business. SOG may outsource some or all of these services to third parties, and a failure of all or part of SOG s relationships with its outsourcing providers could lead to delays in or interruptions of these services. Our reliance on SOG and others as service providers and on SOG s outsourcing relationships, and our limited ability to control certain costs, could have a material adverse effect on our business, financial condition and results of operations.

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Acts of terrorism could have a material adverse effect on our business, financial condition and results of operations.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to the ability to produce, process, transport or distribute oil, natural gas or NGLs. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

Risks Related to Our Relationships with Members of the Sanchez Group

As long as we are controlled by SEP I, your ability to influence the outcome of matters requiring stockholder approval will be limited.

After the completion of this offering, SEP I will own approximately 66.9% of our outstanding common stock, assuming that the underwriters do not exercise their over-allotment option. As long as SEP I has voting control of our company, SEP I will have the ability to take many stockholder actions, including the election or removal of directors, irrespective of the vote of, and without prior notice to, any other stockholder. As a result, SEP I will have the ability to influence or control all matters affecting us, including:

- the composition of our board of directors and, through our board of directors, decision-making with respect to our business direction and policies, including the appointment and removal of our officers;
- any determinations with respect to acquisitions of businesses, mergers or other business combinations;
- our acquisition or disposition of assets; and
- our capital structure.

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SEP I s interests may not be the same as, or may conflict with, the interests of our other stockholders. As a result, actions that SEP I takes with respect to us, as our controlling stockholder, may not be favorable to us. In addition, this voting control may discourage transactions involving a change of control of our company, including transactions in which you, as a holder of our common stock, might otherwise receive a premium for your shares over the then-current market price. Furthermore, SEP I is not prohibited from selling a controlling interest in our company to a third party without your approval or without providing for a purchase of your shares.

We may have potential business conflicts of interest with the Sanchez Group regarding our past and ongoing relationships, and because of SEP I s controlling ownership in us, the resolution of these conflicts may not be favorable to us.

Conflicts of interest may arise between members of the Sanchez Group and us in a number of areas relating to our past and ongoing relationships, including:

- labor, tax, employee benefit, indemnification and other matters arising under agreements with SOG;
- employee recruiting and retention;
- sales or distributions by SEP I of all or any portion of its ownership interest in us, which could be to one of our competitors; and
- business opportunities that may be attractive to both members of the Sanchez Group and us.

We may not be able to resolve any potential conflicts, and, even if we do so, the resolution may be less favorable to us than if we were dealing with an unaffiliated party.

Finally, in connection with this offering, we will enter into several agreements with members of the Sanchez Group. These agreements will be made in the context of a parent-subsidiary relationship. The terms of these agreements may be more or less favorable to us than if they had been negotiated with unaffiliated third parties. While we are controlled by SEP I, SEP I may seek to cause us to amend these agreements on terms that may be less favorable to us than the original terms of the agreement.

Pursuant to the terms of our amended and restated certificate of incorporation, SEP I and its affiliates are not required to offer corporate opportunities to us, and our directors and officers may be permitted to offer certain corporate opportunities to SEP I or its affiliates before us.

Our board of directors includes persons who are also directors and/or officers of members of the Sanchez Group. Our amended and restated certificate of incorporation provides that:

- SEP I and its affiliates are free to compete with us in any activity or line of business;
- we do not have any interest or expectancy in any business opportunity, transaction, or other matter in which SEP I or its affiliates engage or seek to engage merely because we engage in the same or similar lines of business;
- to the fullest extent permitted by law, SEP I and its affiliates will have no duty to communicate their knowledge of, or offer, any potential business opportunity, transaction, or other matter to us, and SEP I and its affiliates are free to pursue or acquire such business opportunity, transaction, or other matter for themselves or direct the business opportunity, transaction, or other matter to its affiliates; and

if any director or officer of any member of the Sanchez Group who is also one of our officers or directors becomes aware of a potential business opportunity, transaction, or other matter (other than one

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expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that business opportunity to us, and will be permitted to communicate or offer that business opportunity to such member of the Sanchez Group (or its affiliates) and that director or officer will not, to the fullest extent permitted by law, be deemed to have (1) breached or acted in a manner inconsistent with or opposed to his or her fiduciary or other duties to us regarding the business opportunity or (2) acted in bad faith or in a manner inconsistent with our best interests or those of our stockholders.

Following this offering, we will continue to depend on SOG to provide us with certain services for our business. The services that SOG will provide to us following the completion of this offering may not be sufficient to meet our needs, and we may have difficulty finding replacement services or be required to pay increased costs to replace these services after our agreements with SOG expire.

Certain services required by us for the operation of our business are currently provided by SOG, including general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals. Prior to the completion of this offering, we will enter into a services agreement with SOG. The services provided under the services agreement will commence on the date this offering is completed and terminate five years thereafter. The term will automatically extend for additional 12-month periods and will be terminable by either party at any time upon 180 days written notice. As a result, we will depend on SOG for services following this offering. See Certain Relationships and Related Party Transactions Agreements Governing the Transaction Operational and Licensing Agreements. While these services are being provided to us by SOG, our operational flexibility to modify or implement changes with respect to such services or the amounts we pay for them will be limited. After the expiration or termination of this agreement, we may not be able to replace these services or enter into appropriate third-party agreements on terms and conditions, including cost, comparable to those that we will receive from SOG under our agreements with SOG.

We may assume unknown liabilities in connection with this offering and in many instances may have no recourse against SEP I or other third parties for losses occurring after this offering.

As part of our acquisition of 100% of the limited liability company interests of SEP Holdings III, the properties we acquire from SEP I will be subject to all existing liabilities, some of which may be unknown at the closing of this offering. Unknown liabilities might include liabilities for cleanup or remediation of undisclosed or unknown environmental conditions, claims that have not been asserted or threatened prior to completion of this offering and tax liabilities. In addition, we will acquire the properties from SEP I on an as is basis and we will have limited or no recourse after closing against the Sanchez Group for liabilities associated with the properties acquired from SEP I, for breaches of representations or warranties by SEP I or for title defects, and we cannot assure you that we have identified all areas of existing or potential exposure. Further, to the extent we will have indemnification rights or a claim for damages for such liabilities, we cannot assure you that the indemnifying party will be able to fulfill its contractual obligations or otherwise satisfy any claims we may have at law or equity.

We may lose our rights to the Sanchez Group s technological database, including its 3D and 2D seismic data, under certain circumstances.

In connection with a services agreement that we will enter into with SOG at the closing of this offering, we will have access to the unrestricted, proprietary portions of the technological database owned and maintained by the Sanchez Group and related to our properties, and SOG will otherwise be required to interpret and use the database, to the extent relating to our properties, for our benefit under the services agreement. See Certain Relationships and Related Party Transactions Agreements Governing the Transaction Operational and Licensing Agreements. This database includes the 2D and 3D seismic data used for our exploration and development projects as well as the well logs, LAS files, scanned well documents and other well documents and software that are necessary for our daily operations. This information is critical for the operation and expansion of our business. Under certain circumstances, including if SOG provides at least 180 days advance written notice of its desire to terminate the services agreement, the license agreement will terminate and we will lose our rights to this technological database unless members of the Sanchez Group permit us to retain some or all of these rights, which they may decline to do in their sole discretion. In such event, we are unlikely to be able to obtain rights to similar information under substantially similar commercial terms or to continue our business operations as proposed and our liquidity, business, financial condition and results of operations will be materially and adversely affected and it could delay or prevent an acquisition of us.

Risks Relating to the Marquis Acquisition

The Marquis acquisition could expose us to potential significant liabilities and in many instances we may have limited or no recourse against Ross Exploration for losses, including title defects.

In connection with the Marquis acquisition, we will assume certain obligations and liabilities, including unknown and contingent liabilities, arising in connection with or relating to the entity or the properties that we will acquire. We have performed a certain level of due diligence in connection with the Marquis acquisition and have attempted to verify the representations of Ross Exploration, but there may be pending, threatened, contemplated or contingent claims against the entity or the properties we acquire related to environmental, title, regulatory, litigation or other matters of which we are unaware. We have not obtained title policies or title insurance on the properties that we will acquire. In addition, we will have limited or no recourse after closing against Ross Exploration for liabilities associated with such properties for breaches of representations or warranties or for title defects, and we cannot assure you that we have identified all areas of existing or potential exposure. For example, Ross Exploration has not made any representations and warranties to us with respect to environmental matters that would entitle us to seek indemnification, and we may not seek an adjustment to the purchase price for any environmental liabilities. Ross Exploration will generally not be liable for any misrepresentation or breach of warranty unless asserted within one year of closing and the aggregate amount of damages with respect to such misrepresentation or breach of warranty exceeds $25,000 individually and $2.0 million in the aggregate and then only to the extent of such excess. Further, to the extent we have indemnification rights or a claim for damages for such liabilities, we may be unable to collect on such indemnification because of disputes with Ross Exploration or its inability to pay. In addition, we may not identify all title defects within the period we are required to assert such defects to claim a reduction in the consideration payable by us. It is also possible that Ross Exploration may prevail in any dispute regarding such title defects. As a result of the Marquis acquisition, we could incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we have limited or no contractual remedies or insurance coverage.

We have not identified any specific use of some of the net proceeds of this offering of shares of common stock in the event of title defects which may reduce the consideration payable under the Marquis Contribution Agreement.

We are entitled to a reduction in the cash consideration payable in exchange for the limited liability company interests of Marquis LLC with respect to title defects that are timely asserted by us and not disputed (or if we prevail in any such dispute). See The Marquis Acquisition. Our board of directors and management will have broad discretion over the use of the proceeds we receive in this offering and might not apply the proceeds in ways that increase the market price of our common stock. We have not identified a specific use for some of the proceeds in the event the consideration payable by us under the Marquis Contribution Agreement is reduced for title defects or other reasons. Any funds received may be used by us for any corporate purpose, which may include pursuit of other business combinations, expansion of our operations or other uses. The failure of our management to use the net proceeds from this offering of shares of common stock effectively could have a material adverse effect on our business and may have an adverse effect on our earnings per share.

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Risks Relating to This Offering

An active and liquid trading market for our common stock may not develop.

Prior to this offering, our common stock was not traded on any market. An active and liquid trading market for our common stock may not develop or be maintained after this offering. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price was negotiated between us and the representative of the underwriters and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in the offering.

Our stock price may be volatile, and purchasers of our common stock could incur substantial losses.

Our stock price may be volatile. The stock market in general has experienced extreme volatility that has often been unrelated to the operating performance of particular companies. As a result of this volatility, investors may not be able to sell their common stock at or above the initial public offering price. The market price for our common stock may be influenced by many factors, including, but not limited to:

- the price of oil and natural gas;
- the success of our exploration and development operations, and the marketing of any oil we produce;
- regulatory developments in the United States and foreign countries where we operate;
- the recruitment or departure of key personnel;
- quarterly or annual variations in our financial results or those of companies that are perceived to be similar to us;
- market conditions in the industries in which we compete and issuance of new or changed securities;
- analysts reports or recommendations;
- the failure of securities analysts to cover our common stock after this offering or changes in financial estimates by analysts;
- the inability to meet the financial estimates of analysts who follow our common stock;
- our issuance of any additional securities;
- investor perception of our company and of the industry in which we compete; and

general economic, political and market conditions.

A substantial portion of our total outstanding shares may be sold into the market. This could cause the market price of our common stock to drop significantly, even if our business is doing well.

All of the shares being sold in this offering will be freely tradable without restrictions or further registration under the federal securities laws, unless purchased by our affiliates as that term is defined in Rule 144 under the Securities Act. The remaining shares of common stock outstanding upon the closing of this

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offering will be held initially by SEP I and Ross Exploration and will be restricted securities as defined in Rule 144 under the Securities Act. Restricted securities may be sold in the U.S. public market only if registered or if they qualify for an exemption from registration, including by reason of Rules 144 or 701 under the Securities Act. All of our restricted shares will be eligible for sale in the public market beginning in 2012, subject in certain circumstances to the volume, manner of sale and other limitations under Rule 144, and also the lock-up agreements described under Underwriting and Conflicts of Interest in this prospectus. In addition, SEP I and its transferees will have the right to require us to register the resale of their shares. See Certain Relationships and Related Party Transactions Agreements Governing the Transactions Registration Rights Agreement. Additionally, we intend to register all shares of our common stock that we may issue under our employee benefit plans. Once we register these shares, they can be freely sold in the public market. Sales of a substantial number of shares of our common stock, or the perception in the market that the holders of a large number of shares intend to sell shares, could reduce the market price of our common stock.

If you purchase shares of our common stock in this offering, you will suffer immediate and substantial dilution of your investment.

The initial public offering price of our common stock is substantially higher than the net tangible book value per share of our common stock. Therefore, if you purchase shares of our common stock in this offering, your interest will be diluted immediately to the extent of the difference between the initial public offering price per share of our common stock and the net tangible book value per share of our common stock after this offering. See Dilution.

We have broad discretion in the use of our net proceeds from this offering and may not use them effectively.

Our management will have broad discretion in the application of the net proceeds from this offering and could spend the proceeds in ways that do not improve our operating results or enhance the value of our common stock. Our stockholders may not agree with the manner in which our management chooses to allocate and spend the net proceeds. The failure by our management to apply these funds effectively could result in financial losses that could have a material adverse effect on our business and cause the price of our common stock to decline. Pending their use, we may invest our net proceeds from this offering in a manner that does not produce income or that loses value. See Use of Proceeds in this prospectus.

We are subject to anti-takeover provisions in our amended and restated certificate of incorporation and amended and restated bylaws and under Delaware law that could delay or prevent an acquisition of our company, even if the acquisition would be beneficial to our stockholders.

Provisions in our amended and restated certificate of incorporation and amended and restated bylaws may delay or prevent an acquisition of us. These provisions may also frustrate or prevent any attempts by our stockholders to replace or remove our current management by making it more difficult for stockholders to replace members of our board of directors, who are responsible for appointing the members of our management team. Furthermore, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the Delaware General Corporation Law, or the DGCL, which prohibits, with some exceptions, stockholders owning in excess of 15% of our outstanding voting stock from merging or combining with us. Finally, our amended and restated bylaws establish advance notice requirements for nominations for election to our board of directors and for proposing matters that can be acted upon at stockholder meetings. Although we believe these provisions together provide an opportunity to receive higher bids by requiring potential acquirers to negotiate with our board of directors, they would apply even if an offer to acquire us may be considered beneficial by some stockholders. See Description of Capital Stock Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, our Amended and Restated Bylaws and Delaware Law.

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We will be a controlled company within the meaning of the NYSE rules and, as a result, will qualify for, and intend to rely on, exemptions from certain corporate governance requirements that provide protection to stockholders of other companies.

After the completion of this offering, SEP I will own more than 50% of the voting power of all then outstanding shares of our capital stock entitled to vote generally in the election of directors, and we will be a controlled company under the NYSE corporate governance standards. As a controlled company, we intend to rely on certain exemptions from the NYSE standards that will enable us not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of our board of directors consists of independent directors;
- we have a nominating and governance committee that is composed entirely of independent directors, with a written charter addressing the committee s purpose and responsibilities;
- we have a compensation committee that is composed entirely of independent directors, with a written charter addressing the committee s purpose and responsibilities; and
- we conduct an annual performance evaluation of the nominating and governance committee and compensation committee.

We intend to rely on some or all of these exemptions, and, as a result, you will not have the same protection afforded to stockholders of companies that are subject to all of the NYSE corporate governance requirements.

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FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategies;
- ability to replace the reserves we produce through drilling and property acquisitions;
- expected benefits and closing of the Marquis acquisition;
- drilling plans and locations;
- oil and natural gas reserves;
- technology;
- realized oil and natural gas prices;
- production volumes;
- oil and natural gas production expenses;
- general and administrative expenses;
- future operating results;
- cash flows and liquidity;
- availability of drilling and production equipment;
- availability of oil field labor;
- capital expenditures;

availability and terms of capital;

marketing of oil and natural gas;

general economic conditions;

competition in the oil and natural gas industry;

effectiveness of risk management activities;

environmental liabilities;

counterparty credit risk;

governmental regulation and taxation;

developments in oil-producing and natural-gas producing countries; and

plans, objectives, expectations and intentions.

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These types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in Prospectus Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business and Properties and other sections of this prospectus. In some cases, you can identify forward-looking statements by terminology such as may, will, could, should, expect, plan, project, intend, anticipate, believe, estimate, pr target, continue, the negative of such terms or other comparable terminology.

The forward-looking statements contained in this prospectus are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this prospectus are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in Risk Factors and elsewhere in this prospectus. All forward-looking statements speak only as of the date of this prospectus. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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USE OF PROCEEDS

We will receive net proceeds of approximately $202.7 million from the sale of the common stock offered by us after deducting estimated expenses and underwriting discounts and commissions of approximately $17.3 million.

The following table sets forth our proceeds from the offering of shares of our common stock and our uses of the proceeds that we expect to receive from this offering.

Proceeds (in millions)		Uses of Proceeds (in millions)	
Gross proceeds from this offering	$ 220	Cash consideration to SEP I for the contribution by SEP I to us of all the limited liability company interests in SEP Holdings III(2)	$ 50
		Cash consideration for all of the limited liability company interests in Marquis LLC(3)	$ 89
		Underwriting discounts and commissions(4)	$ 14
		Fees and expenses associated with this offering and the formation transactions(5)	$ 3
		Drilling, exploration and acquisition expenditures and general corporate purposes(6)	$ 64
Total(1)	$ 220	Total	$ 220

(1) If the underwriters exercise their option to purchase additional shares of common stock in full, the gross proceeds would be approximately $253 million.

(2) In addition to the cash consideration, we will issue 22,090,909 shares of common stock to SEP I for the contribution by SEP I to us of all the limited liability company interests in SEP Holdings III. If the underwriters exercise their option to purchase in full up to an additional 1,500,000 shares of common stock, the total cash consideration to SEP I would be approximately $65.4 million, the number of shares of common stock issued to SEP I (as presented in this prospectus) will decrease by one-half of the aggregate number of shares of common stock purchased by the underwriters pursuant to such exercise, and the number of shares issued to the public (as presented in this prospectus) will increase by the aggregate number of shares of common stock purchased by the underwriters pursuant to such exercise. One-half of the net proceeds from any exercise of the underwriters option to purchase additional shares of common stock will be paid to SEP I. This payment of net proceeds and/or issuance of shares of common stock to SEP I is intended to represent a portion of the consideration paid to SEP I for its contribution of all the limited liability company interests in SEP Holdings III to us.

(3) The final amount of the cash consideration paid to Ross Exploration is subject to adjustment as described in The Marquis Acquisition. We will use any difference between the indicated amount and the actual cash consideration paid for the contribution to us of the limited liability company interests in Marquis LLC for general corporate purposes. In addition to the cash consideration, we will issue 909,091 shares of our common stock to Ross Exploration for the contribution by it to us of all the limited liability company interests in Marquis LLC.

(4) If the underwriters exercise their option to purchase shares of common stock in full, the underwriting discounts and commissions will be approximately $16.4 million.

(5) In connection with the closing of this offering, we will reimburse SEP I for the fees and expenses that it paid on our behalf in connection with this offering and the formation transactions.

(6) We plan to use a portion of the net proceeds from this offering of approximately $64 million, along with cash generated from the results of operations, to fund our $413 million capital expenditure budget for the period from January 2012 through December 2013. This budget plans for the drilling of 75 gross (46 net) wells. Pending use of the remaining net proceeds of this offering, and any net proceeds paid to us from the exercise of the underwriters option to purchase additional shares of common stock from us, we intend to invest the net proceeds in interest bearing, investment-grade securities.

DIVIDEND POLICY

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities.

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CAPITALIZATION

The following table shows our unaudited cash and cash equivalents and capitalization as of September 30, 2011:

- on a historical basis;
- pro forma to reflect (i) our change in tax status from a partnership to a corporation, (ii) the recording of a distribution payable to SEP I in connection with the contribution by SEP I to us of all the limited liability company interests in SEP Holdings III and the issuance by us of 22,090,909 shares of common stock to SEP I, and (iii) the recording of a liability for acquisition consideration payable to Ross Exploration and the issuance by us of 909,091 shares of common stock to Ross Exploration; and
- pro forma as adjusted to reflect the issuance and sale of common stock to the public at the initial public offering price of $22.00 per share and the application of the net proceeds from this offering as described under Use of Proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with Summary Formation Transactions and Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of September 30, 2011		
	Historical	Pro Forma	Pro Forma As Adjusted
		(in thousands)	
Cash and cash equivalents	$ -	$ -	$ 64,285
Distribution payable	$ -	$ 50,000	$ -
Marquis acquisition consideration payable	-	88,700	-
Parent net investment/stockholders equity:			
Parent net investment	34,719	-	-
Common stock, $0.01 par value; 1,000 shares authorized, none issued and outstanding (historical); 150,000,000 shares authorized, 23,000,000 shares and 33,000,000 shares issued and outstanding (Pro Forma and Pro Forma As Adjusted, respectively)	-	230	330
Paid-in capital	-	4,490	207,090
Total parent net investment/stockholders equity	34,719	4,720	207,420
Total capitalization	$ 34,719	$ 143,420	$ 207,420

The number of shares of common stock shown as issued and outstanding in the table set forth above excludes shares of common stock expected to be reserved for issuance under our Long Term Incentive Plan.

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of common stock sold in this offering will exceed the net tangible book value per share after this offering. Net tangible book value is our total tangible assets less total liabilities. As of September 30, 2011, after giving effect to the transactions described under Prospectus Summary Formation Transactions, including this offering of common stock and the application of the related net proceeds, our pro forma as adjusted net tangible book value was $207.4 million, or $6.29 per share. Purchasers of common stock in this offering will experience substantial and immediate dilution in net tangible book value per common share for accounting purposes, as illustrated in the following table:

Initial public offering price per share		$ 22.00
Pro forma net tangible book value per share before this offering(1)	$ 0.19	
Increase in net tangible book value per share attributable to purchasers in this offering	6.10	
Less: Pro forma as adjusted net tangible book value per share after this offering(2)		6.29
Immediate dilution in net tangible book value per share to purchasers in this offering		$ 15.71

(1) Determined by dividing the pro forma net tangible book value of our net assets immediately prior to the offering by the number of shares to be issued to SEP I as partial consideration for its contribution of the limited liability company interests in SEP Holdings III and to Ross Exploration as partial consideration for the limited liability company interests in Marquis LLC.

(2) Determined by dividing our pro forma as adjusted net tangible book value, after giving effect to the application of the expected net proceeds of this offering, by the total number of shares outstanding after this offering.

The following table sets forth the number of shares that we will issue and the total consideration contributed to us by SEP I in respect of its shares and by Ross Exploration in connection with the Marquis acquisition in respect of its shares and by the purchasers of shares in this offering upon consummation of the transactions contemplated by this prospectus:

	Shares Purchased		Total Consideration	
	Number	Percent	$ (in millions)	Percent
Existing stockholders(1)	23,000,000	69.7%	$ 4.7	2.1%
Purchasers in the offering(2)	10,000,000	30.3%	220.0	97.9%
Total	33,000,000	100.0%	$ 224.7	100.0%

(1) The assets contributed by SEP I are reflected at SEP I s historical cost in accordance with GAAP. The assets contributed by Ross Exploration in connection with the Marquis acquisition are reflected at the approximately $109 million purchase price.

(2) Total consideration is after deducting underwriting discounts and estimated offering expenses.

If the underwriters exercise their option to purchase additional shares in full, the following will occur:

the percentage of shares of our common stock held by existing stockholders would decrease to 65.9% of the total number of shares of our common stock outstanding after this offering and the total cash consideration to SEP I would increase by approximately $15.4 million; and the percentage of shares of our common stock held by new investors would increase to approximately 34.1% of the total number of shares of our common stock outstanding after this offering.

In addition, we may choose to raise additional capital due to market conditions or strategic considerations even if we believe we have sufficient funds for our current or future operating plans. To the extent that we raise additional capital through the sale of equity or convertible debt securities, the issuance of these securities could result in further dilution to our stockholders.

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THE MARQUIS ACQUISITION

The Marquis acquisition is structured as a contribution to us of all of the limited liability company interests of Marquis LLC, which was recently formed for the sole purpose of owning all right, title and interest in and to certain interests in oil and gas properties, rights and related assets identified in the Marquis Contribution Agreement. The acreage that we are acquiring is subject to an overriding royalty interest that was previously conveyed by Ross Exploration to an affiliate as part of the transactions contemplated by the Marquis Contribution Agreement. The overriding royalty interest is equal to the difference (expressed as a percentage), if positive, between (i) the difference (expressed as a percentage) between (A) 100% minus (B) the sum of all existing royalty reserved under such properties, rights and interests plus all currently existing overriding royalty interests and similar burdens on production, minus (ii) 75%.

The purchase price for the Marquis acquisition will be approximately $109 million, subject to certain adjustments described in the Marquis Contribution Agreement (and exclusive of certain costs and expenses we have agreed to reimburse Ross Exploration in cash for at closing), approximately $89 million of which will be paid in cash and $20 million of which will be paid in shares of our common stock, and an overriding royalty interest discussed above. The number of shares to be issued will be determined by dividing (i) $20 million by (ii) the price to the public of our shares in this offering. Based on the initial public offering price of $22.00 per share, we will issue 909,091 shares of our common stock as partial consideration for the Marquis acquisition. Of these shares, Ross Exploration will be prohibited from transferring, pledging or otherwise disposing of 50% of the shares of common stock received by it for a period of one year following the closing. All of these shares are also subject to the lock-up agreement described under Underwriting and Conflicts of Interest Lock-Up Agreements. The closing of the Marquis acquisition is expected to occur immediately following the closing of this offering.

The Marquis Contribution Agreement provides that the closing must take place on or before January 31, 2012, the outside date (provided, that we may elect to extend the outside date to February 28, 2012, in which case the purchase price per net mineral acre will increase by an additional $50.00, or approximately $2.75 million, which will be reflected by increasing the cash portion of the consideration payable by us at closing), and is subject to (i) the accuracy of the respective representations and warranties made by us and Ross Exploration and compliance by us and Ross Exploration with our respective obligations under the Marquis Contribution Agreement (subject to certain materiality exceptions), (ii) no proceedings pending or threatened seeking to prohibit the consummation of the transactions contemplated by the Marquis Contribution Agreement and (iii) completion of this offering.

The Marquis Contribution Agreement contains customary representations and warranties of the parties which relate to various aspects of the properties to be acquired by us and other matters of the parties. The representations and warranties of Ross Exploration survive the closing for a period of one year. Ross Exploration will be required to indemnify us and our affiliates against all losses arising from or relating to any breaches of its representations or warranties or covenants or agreements under the Marquis Contribution Agreement. The Marquis Contribution Agreement provides that no indemnification claim against Ross Exploration can be made with respect to representations and warranties for individual losses less than $25,000 and until losses total more than $2 million, and then only to the extent that such losses exceed $2 million. We, on the other hand, have generally agreed to indemnify Ross Exploration for any and all losses suffered by it and its affiliates relating to the ownership and operation of the properties to be acquired whenever arising, except to the extent Ross Exploration has otherwise agreed to indemnify us. In addition, Ross Exploration has agreed to indemnify us for certain tax liabilities attributable to the properties to be acquired or incurred by Marquis LLC before the closing and we have agreed to indemnify Ross Exploration for certain tax liabilities attributable to the properties to be acquired or incurred by Marquis LLC after closing.

The Marquis Contribution Agreement contains additional provisions relating to title defects. Potential reductions in the cash portion of the purchase price, including for claims relating to title defects against Ross Exploration in excess of $15 million, give us the right to elect not to close the Marquis acquisition for failure to meet a condition precedent to closing. Claims relating to title defects must be asserted by us not later than

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January 31, 2012, in which case any such defects not identified by us will at such time be deemed waived. For us to be entitled to reduce the cash portion of the purchase price prior to closing for title defects (unless Ross Exploration cures the defect to our reasonable satisfaction before closing or we agree to waive the defect) or deposit any disputed amounts or amounts related to defects that Ross Exploration notifies us that it intends to cure into escrow, we must notify Ross Exploration of any title defects at least five business days before the anticipated closing date. If any lease or other property has an allocated value of $5,000 or less or has not been given an allocated value, such lease or other property will be deemed not to have any title defects. No adjustments will be made to the cash portion of the purchase price unless title defects exceed $1 million, subject to certain exceptions, and then only to the extent that such title defects exceed $1 million. Ross Exploration has 30 business days from January 31, 2012 (which we refer to as the post-closing cure period) to cure any title defects, subject to our right to deposit into escrow the cash portion of the purchase price payable at closing for any uncured and timely asserted defects or any unresolved and disputed defects arising prior to the fifth business day before closing. If Ross Exploration disputes any asserted title defects, we will attempt to resolve the dispute through good faith negotiations prior to closing and, if we cannot do so, we will submit the dispute for arbitration after closing of the Marquis acquisition. Amounts with respect to title defects held in escrow will be remitted to Ross Exploration (if the defect is cured within the post-closing cure period or Ross Exploration prevails in any dispute regarding such title defect) or us (if the defect is not so cured or we prevail in any dispute regarding such title defect), as applicable.

No later than 30 days after the post-closing cure period we will deliver to Ross Exploration a final settlement statement setting forth each adjustment to the cash portion of the purchase price contemplated by the Marquis Contribution Agreement, including any additional title defects discovered by us within the permitted period but after the fifth business day prior to closing. Ross Exploration will have 15 days after receipt of the final settlement statement to object and we will have 15 days from receipt of any such objections to respond; any disputes will be submitted for arbitration. If the cash portion shown on the final settlement statement is greater than that paid by us at closing, we will pay the difference to Ross Exploration within five business days after the settlement statement has been finalized. If the cash portion of the purchase price is less than that paid by us at closing, Ross Exploration will pay the difference to us with five business days after the settlement statement has been finalized.

Between execution of the Marquis Contribution Agreement and the closing, Ross Exploration has agreed to (i) not act in any manner with respect to the acquired properties other than in the normal, usual and customary manner, consistent with prior practice, dispose of, encumber or relinquish any of the acquired properties (other than any relinquishment resulting from the expiration of any lease or material contract in accordance with its terms), or waive, compromise or settle any material right or claim with respect to any of the acquired properties; (ii) use commercially reasonable efforts to preserve relationships with all third parties having business dealings with respect to the acquired properties; and (iii) cooperate with us in the notification of all applicable governmental regulatory authorities of the transactions contemplated by the Marquis Contribution Agreement and cooperate with us in obtaining the issuance by each such authority of such permits, licenses and authorizations as may be necessary for us to own and operate the acquired properties following the closing.

The Marquis Contribution Agreement may be terminated (i) by mutual written consent, (ii) by either party if the closing has not occurred by January 31, 2012 or February 28, 2012, if we give notice to Ross Exploration of our desire to extend the outside date (unless a party s failure to comply with its obligations under the agreement caused the closing not to occur) and agree to pay an additional $50.00 per net mineral acre as described above, or (iii) by either party in the event we withdraw the registration statement of which this prospectus is a part or the SEC issues a stop order before the issuance of shares in this offering.

We will have the right, but not the obligation, to acquire any additional mineral rights now owned or hereafter acquired by Ross Exploration or its affiliates prior to closing in certain other portions of Fayette and Lavaca Counties, Texas or within one mile of any acquired properties in Atascosa, Webb or DeWitt Counties, Texas (collectively referred to as the Protected Area) for a purchase price of $1,981.13 per mineral acre plus certain reimbursable costs and expenses incurred by Ross Exploration in connection with the maintenance of the properties, provided that Ross Exploration may reserve an overriding royalty interest in such properties equal to the difference (expressed as a percentage), if positive, between (i) the difference (expressed as a percentage) between (A) 100% minus (B) the sum of all existing royalty reserved under such properties, rights and interests plus all currently existing overriding royalty interests and similar burdens on production, minus (ii) 75%. For a period of two years following the closing, Ross Exploration will not acquire any oil and gas leases or related interests in the acquired properties or in the Protected Area.

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SELECTED FINANCIAL DATA

The selected financial data as of December 31, 2009 and 2010 and for the years ended December 31, 2008, 2009 and 2010 are derived from our audited historical financial statements included elsewhere in this prospectus. The selected historical financial data as of September 30, 2011 and for the nine months ended September 30, 2010 and 2011 are derived from our unaudited historical financial statements included elsewhere in this prospectus and from our financial records. The selected financial data as of December 31, 2008 is derived from SEP I s financial records. The results of operations for the interim periods are not necessarily indicative of operating results for the entire year or any future period.

Our historical financial statements have been prepared on a carve-out basis from the accounts of SEP I. These carve-out financial statements include all assets, liabilities and results of operations of the unconventional oil and natural gas properties and related assets to be contributed to us by SEP I for the periods presented.

Financial information for periods prior to 2008 is not presented. The properties did not have any production for periods prior to SEP I s acquisition of them and we believe that the omission of financial information for these periods is immaterial and unnecessary with respect to an understanding of our financial results and condition or any related trends and business prospects.

You should read the following table in conjunction with Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations and our financial statements included elsewhere in this prospectus. Among other things, those historical financial statements include more detailed information regarding the basis of presentation for the following information.

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
				(Unaudited)	
			(in thousands)		
Revenues:					
Oil sales	$ -	$ 241	$ 4,404	$ 1,465	$ 9,433
Natural gas sales	-	-	149	-	437
Total revenues	-	241	4,553	1,465	9,870
Costs and expenses:					
Oil & natural gas production expenses	-	9	391	70	1,209
Production and ad valorem taxes, net	-	11	214	68	551
Depreciation, depletion and amortization	-	415	1,428	324	2,761
Accretion expense	-	-	2	1	4
Impairment of oil and natural gas properties	-	614	-	-	-
Gain on sale of oil and natural gas properties	-	(2,686)	-	-	-
General and administrative	1,247	1,833	5,276	4,121	3,503
Total operating costs and expenses	1,247	196	7,311	4,584	8,028
Operating income (loss)	(1,247)	45	(2,758)	(3,119)	1,842
Other income:					
Unrealized gain on derivatives	-	-	-	-	1,558
Net income (loss)	$ (1,247)	$ 45	$ (2,758)	$ (3,119)	$ 3,400
Cash Flow Data:					
Net cash (used in) provided by operating activities	$ (1,247)	$ (1,710)	$ (3,777)	$ (3,140)	$ 2,198
Net cash (used in) provided by investing activities	$ (14,197)	$ 2,734	$ (7,925)	$ (9,101)	$ (10,917)
Net cash (used in) provided by financing activities	$ 15,444	$ (1,024)	$ 11,702	$ 12,240	$ 8,719

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	As of December 31,			As of September 30,
	2008 (Unaudited)	2009	2010	2011 (Unaudited)
	(in thousands)			
Balance Sheet Data:				
Working capital (deficit)	$ (65)	$ 59	$ (1,818)	$ (379)
Total assets	$ 14,262	$ 13,275	$ 26,764	$ 39,681
Parent net investment	$ 14,197	$ 13,218	$ 22,162	$ 34,719

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MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management s Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this prospectus, particularly in Risk Factors and Forward-Looking Statements, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Overview

We are an independent exploration and production company focused on the exploration, development and acquisition of unconventional oil and natural gas resources and recently formed for the purpose of acquiring unconventional oil and natural gas assets, including those that will be contributed to us as part of the transactions described under Prospectus Summary Formation Transactions . After this offering, SEP I will own approximately 66.9% of our outstanding common stock, assuming no exercise of the underwriters over-allotment option. Our operational and capital spending focus for the period from January 2012 through December 2013 will be on accelerating the development of our undeveloped oil focused Eagle Ford Shale assets and increasing our acreage position in that trend through focused leasehold and production acquisitions.

The use of our capital for the accelerated development and expansion of our Eagle Ford Shale assets allows us to direct our capital resources to what we believe are the most attractive opportunities in today s market conditions. Our affiliation with members of the Sanchez Group allows us to leverage their experience and relationships to grow in a cost effective and unique manner as compared to most of our industry peers. Although we are newly formed, the history and experience we have through our affiliation with the Sanchez Group is significant and is expected to give us a full range of technical and administrative skills, experience and manpower to effectively accelerate our growth. Members of the Sanchez Group are headquartered with us in Houston, Texas and they have a long history of oil and natural gas operation in multiple basins across the United States, particularly in South Texas, where we will be focused initially. Those historical operations began in Laredo, Texas in 1972, where SOG still has an office, and members of the Sanchez Group have owned and operated businesses and ranches in South Texas continuously since that time, which gives us an extraordinary level of knowledge and access to mineral and surface rights owners in our areas of operation.

Our Properties

SEP I began acquiring leases in the Eagle Ford Shale trend in 2008, as well as leases in the Haynesville Shale trend in Natchitoches Parish, Louisiana and the Heath, Three Forks and Bakken Shale trends in northern Montana. Largely due to the recent disparity between oil and natural gas prices, our recent focus has been the delineation and development of our Eagle Ford Shale acreage position which sits within the black oil and volatile oil windows of the Eagle Ford Shale trend. We use the term black oil to describe a quality of oil with an API gravity of 40º or less and with a gas-to-oil ratio of 500 cubic feet per barrel or less. We use the term volatile oil to describe a quality of oil with an API gravity greater than 40º and with a gas-to-oil ratio of greater than 500 cubic feet per barrel. Initially, we focused on our Palmetto area in Gonzales County, Texas. After acquiring the lease rights to a large, approximately 14,000 acre ranch in August 2008, we sold a 50% interest in the position to Hilcorp and created a large surrounding area of mutual interest, or AMI, with Hilcorp in exchange for cash and a complete carry on the costs to drill and complete the first three wells in the AMI. Under the terms of the AMI, we now share all ownership and costs on a 50/50 basis. The first three wells in the

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AMI, known as the Barnhart # s 1H, 2H and 3H, were drilled and completed in 2010. The Barnhart #4H commenced drilling in late December 2010 and was completed and placed on production in February of 2011. The four wells drilled on our acreage had an average 30-day per well choke restricted production rate of 788 boe/d (665 bopd and 737 mcf/d). During this time period, our acreage position within the AMI was expanded as the result of additional leasing and acquisition activities such that as of September 30, 2011 our net acreage ownership was approximately 9,400 acres. We have drilled the Barnhart #5H and the Barnhart #6H in Gonzales County, Texas. We recently finished completion activities on these two wells and they commenced production in December 2011. The initial 24-hour production rates for the Barnhart #5H and #6H were 1,435 boe/d and 1,382 boe/d, respectively, using a 14/64 inch restricted choke. We have a 50% working interest in all of the Barnhart wells.

Hilcorp, our 50/50 working interest partner and operator in our Palmetto area, recently closed the sale of their entire Eagle Ford Shale asset base, to Marathon. Marathon is now our 50/50 working interest partner in Palmetto and has expressed to us a desire to accelerate drilling in the Palmetto area. We currently expect to drill 39 gross (19 net) wells in our Palmetto area for the period from January 2012 through December 2013.

Our Maverick area consists of approximately 27,700 net acres in Zavala and Frio Counties, Texas. Recent industry drilling activity has increased around our acreage position. Based upon our drilling and technical evaluation, we believe that the Eagle Ford Shale is of the same approximate thickness and organic content in this area as in our Palmetto area, although it is shallower than in our Palmetto area, being approximately 5,500 feet versus 9,000 to 11,000 feet in our Palmetto area. The Maverick area is prospective for the Buda Limestone, Austin Chalk and Pearsall Shale formations as well as the Eagle Ford Shale. We recently drilled and completed our first horizontal, multi-stage hydraulically fractured Eagle Ford Shale well in this area, the Alpha Ware #1H well. The well, in which we have a 60% operated working interest, was placed on production in July 2011 at an initial 30-day average production rate of 242 bopd. We are currently drilling a vertical Eagle Ford Shale well in this area in an effort to evaluate the relative economics of vertical versus long-lateral completions in this part of the trend. Furthermore, the Buda Limestone has proven to be economically productive in this area and our intent is to establish a drilling program to develop this significant resource in the future. For the period from January 2012 through December 2013, we expect to drill 18 gross (9 net) wells with working interests varying from 40% to 100% in our Maverick area.

On November 8, 2011, we entered into a contribution agreement, or the Marquis Contribution Agreement, with Ross Exploration, Inc., or Ross Exploration, to acquire a 100% working interest and an approximate 75% net revenue interest in approximately 54,900 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties, Texas. We have agreed to pay Ross Exploration approximately $89 million in cash, subject to customary pre- and post-closing adjustments (and exclusive of certain costs and expenses for which we have agreed to reimburse Ross Exploration in cash at closing), and 909,091 shares of our common stock. The acreage that we are acquiring is subject to an overriding royalty interest that was previously conveyed by Ross Exploration to an affiliate as part of the transactions contemplated by the Marquis Contribution Agreement. Other operators in this project area have recently reported initial per well production rates of 1,000 to 1,200 boe/d. For the period from January 2012 through December 2013, we plan to spend approximately $135 million to drill 18 gross (18 net) wells in our Marquis area.

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The following table represents the historical performance of the Barnhart wells # s 1H 4H and the Alpha Ware #1H well.

Completion Date	Days On Production	Well Name	Project Area	Lateral Length	Stages	Initial Choke	10-Day Average Gross Daily Production (boe)	30-Day Average Gross Daily Production (boe)	Cumulative Production(1) (boe)
7/2/10	440	Barnhart #1H	Palmetto	3,902	12	17/64	499	491	77,504
10/25/10	334	Barnhart #2H	Palmetto	5,100	12	13/64	1,055	1,102	153,268
11/7/10	330	Barnhart #3H	Palmetto	5,320	16	15/64	696	663	99,843
2/22/11	230	Barnhart #4H	Palmetto	5,507	16	15/64	821	893	153,066
7/8/11	95	Alpha Ware #1H	Maverick	6,513	20	N/A	359	242	14,262

(1) As of October 10, 2011.

Our historical financial statements have been prepared on a carve-out basis from the accounts of SEP I. These carve-out financial statements include all assets, liabilities and results of operations of the unconventional oil and natural gas assets and related equipment for the periods presented to be contributed to us by SEP I. Our revenue, profitability and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Sustained periods of low oil and natural gas prices could materially and adversely affect our financial condition, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. Previously, SEP I funded the acquisition and development of our properties with its equity capital and we expect to have no debt immediately after this offering. We currently expect that the net proceeds from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our liquidity options. We are currently de-emphasizing the development of our Haynesville Shale natural gas area due to the disparity between oil and natural gas prices. Our Eagle Ford Shale assets are in the black oil and volatile oil windows of the trend and may offer higher rates of return as a result of the relative strength of oil prices as compared to natural gas.

How We Conduct Our Business and Evaluate Our Operations

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, our willingness to acquire non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- production volumes;

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- realized prices on the sale of oil, natural gas and NGLs, including the effect of our commodity derivative contracts;
- oil and natural gas production expenses;
- maintenance capital expenditures;
- general and administrative expenses;
- net cash provided by operating activities; and
- Adjusted EBITDA.

Production Volumes

Production volumes directly impact our results of operations. For more information about our production volumes, please read Business and Properties Oil and Natural Gas Reserves and Production Production, Revenues and Price History.

Realized Prices on the Sale of Oil and Natural Gas

Factors Affecting the Sales Price of Oil and Natural Gas. We will market our oil and natural gas production to a variety of purchasers based on regional pricing. The relative prices of oil and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, weather cycles and other events. In addition, relative prices are heavily influenced by product quality and location relative to consuming and refining markets.

Oil. The NYMEX-WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX-WTI price as a result of quality and location differentials. Quality differentials to NYMEX-WTI prices result from the fact that crude oils differ from one another in their molecular makeup, which plays an important part in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: (1) the oil s American Petroleum Institute, or API, gravity and (2) the oil s percentage of sulfur content by weight. In general, lighter oil (with higher API gravity) produces a larger number of lighter products, such as gasoline, which have higher resale value and, therefore, normally sells at a higher price than heavier oil. Oil with low sulfur content (sweet oil) is less expensive to refine and, as a result, normally sells at a higher price than high sulfur-content oil (sour oil).

Location differentials to NYMEX-WTI prices result from variances in transportation costs based on the produced oil s proximity to the major consuming and refining markets to which it is ultimately delivered. Oil that is produced close to major consuming and refining markets, such as near Cushing, Oklahoma, is in higher demand as compared to oil that is produced farther from such markets. Consequently, oil that is produced close to major consuming and refining markets normally realizes a higher price (i.e., a lower location differential to NYMEX-WTI).

The oil produced from our properties is a combination of sweet and sour oil, varying by location. We sell our oil at the NYMEX-WTI price, which is adjusted for quality and transportation differential, depending primarily on location and purchaser. The differential varies, but our oil normally sells at a discount to the NYMEX-WTI price.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2010, the NYMEX-WTI oil price ranged from a high of $81.04 per bo to a low of $33.98 per bo, while the NYMEX-Henry Hub natural gas price ranged from a high of $6.11 per mmbtu to a low of $1.88 per mmbtu. For the five years ended December 31, 2009, the NYMEX-WTI oil price ranged from a high of $145.29 per bo to a low of $31.41 per bo, while the NYMEX-Henry Hub natural gas price ranged from a high of $15.39 per mmbtu to a low of $1.88 per mmbtu.

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Natural Gas. The NYMEX-Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX-Henry Hub price as a result of quality and location differentials. Quality differentials to NYMEX-Henry Hub prices result from: (1) the btu content of natural gas, which measures its heating value, and (2) the percentage of sulfur, CO_2 and other inert content by volume. Wet natural gas with a high btu content sells at a premium to low btu content dry natural gas because it yields a greater quantity of NGLs. Natural gas with low sulfur and CO_2 content sells at a premium to natural gas with high sulfur and CO_2 content because of the added cost to separate the sulfur and CO_2 from the natural gas to render it marketable. The wet natural gas is processed in third-party natural gas plants and residue natural gas as well as NGLs are recovered and sold. The dry natural gas residue from our properties is generally sold based on index prices in the region from which it is produced.

Location differentials to NYMEX-Henry Hub prices result from variances in transportation costs based on the natural gas proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds. Generally, these index prices have historically been at a discount to NYMEX-Henry Hub natural gas prices.

Commodity Derivative Contracts. We expect to adopt a hedging policy designed to reduce the impact to our cash flows from commodity price volatility. At the closing of this offering, SEP I will contribute to us a commodity derivative contract with a deferred premium cost of approximately $1.9 million covering 1,000 bopd for the 2012 fiscal year. The contract is a put spread where we will be long a $90 oil put and short a $70 oil put. Our put spread protects us from oil prices falling below $90 until such time as prices fall below $70, in which case we receive the market price plus the $20 spread between $90 and $70. SEP I incurred a premium of approximately $1.9 million, which it deferred, at the time of entering into the derivative contract. We will use a portion of the proceeds from this offering to pay the deferred premium amount.

Oil and Natural Gas Production Expenses. We strive to increase our production levels to maximize our revenue. Oil and natural gas production expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water injection and disposal, and materials and supplies comprise the most significant portion of our oil and natural gas production expenses. Oil and natural gas production expenses do not include general and administrative costs or production and other taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased oil and natural gas production expenses in periods during which they are performed.

A majority of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we incur power costs in connection with various production related activities such as pumping to recover oil and natural gas and separation and treatment of water produced in connection with our oil and natural gas production. Over the life of natural gas fields, the amount of water produced may increase for a given volume of natural gas production, and, as pressure declines in natural gas wells that also produce water, more power will be needed to provide energy to artificial list systems that help to remove produced water from the wells. Thus, production of a given volume of natural gas gets more expensive each year as the cumulative natural gas produced from a field increases until, at some point, additional production becomes uneconomic.

We monitor our operations to ensure that we are incurring operating costs at the optimal level. Accordingly, we monitor our production expenses and operating costs per well to determine if any wells or properties should be shut in, recompleted or sold. We typically evaluate our oil and natural gas operating costs on a per boe basis. This unit rate allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers.

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Production and Ad Valorem Taxes. Texas regulates the development, production, gathering and sale of oil and natural gas, including imposing production taxes and requirements for obtaining drilling permits. For oil production, Texas currently imposes a production tax at 4.6% of the market value of the oil produced and 3/16 of one cent per bo produced, and for natural gas, Texas currently imposes a production tax at 7.5% of the market value of the natural gas produced. However, a significant portion of the wells in Texas are either currently exempt from production tax due to high cost natural gas abatement or reduced rate for post-production cost recoupment. Louisiana also currently imposes a production tax for natural gas at $0.164 per mcf of natural gas produced. Ad valorem taxes are generally tied to the valuation of the oil and natural gas properties; however, these valuations are reasonably correlated to revenues, excluding the effects of any commodity derivative contracts.

General and Administrative Expenses. At the closing of this offering, we will enter into a services agreement with SOG pursuant to which, among other things, it will perform all operational, management and administrative services on our behalf. For a detailed description of the services agreement, please read Certain Relationships and Related Party Transactions Agreements Governing the Transactions Operational and Licensing Agreements. Under the services agreement, we will reimburse SOG for all direct and indirect costs incurred on our behalf, including for any such costs arising from amounts paid directly by other members of the Sanchez Group on SOG s behalf or borrowed by SOG from other members of the Sanchez Group, in each case in connection with the performance by SOG of services on our behalf. General and administrative expenses related to being a publicly traded company include: Exchange Act reporting expenses; expenses associated with Sarbanes-Oxley compliance; expenses associated with listing on the NYSE; independent auditor fees; legal fees; investor relations expenses; registrar and transfer agent fees; director and officer liability insurance costs; and director compensation. As a publicly-traded company at the closing of this offering, we expect that general and administrative expenses will increase.

Income Tax Expense. Our properties have historically been owned by a limited partnership that is not a taxable entity and does not directly pay federal income taxes. Upon closing of this offering, we will be subject to federal and state income taxes, which may affect future operating results and cash flows.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss):

Plus:

- Interest expense, including realized and unrealized losses on interest rate derivative contracts;
- Income tax expense (benefit);
- Depreciation, depletion, and amortization;
- Accretion of asset retirement obligations;
- Loss (gain) on settlement of asset retirement obligations;
- Loss (gain) on sale of oil and natural gas properties;
- Unrealized losses on derivatives;

- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

Less:

- Interest income;
- Unrealized gains on derivatives; and
- Other non-recurring items that we deem appropriate.

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Adjusted EBITDA will be used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess:

- our operating performance as compared to that of other companies and companies in our industry, without regard to financing methods, capital structure or historical cost basis; and

- our ability to incur and service debt and fund capital expenditures.

Adjusted EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. For further discussion, please read Prospectus Summary Non-GAAP Financial Measures.

Outlook

Beginning in the second half of 2008, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. During this same period, North American natural gas supply was increasing as a result of the rise in domestic unconventional natural gas production. The combination of lower energy demand due to the economic slowdown and higher North American natural gas supply resulted in significant declines in oil, NGL and natural gas prices. While oil and NGL prices started to steadily increase beginning in the second quarter of 2009, natural gas prices remained depressed throughout 2009 and have remained low, relative to the prices in 2007 and 2008, due to a continued increase in natural gas supply despite weaker offsetting demand growth. The outlook for a worldwide economic recovery in 2012 remains uncertain, and the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, it is likely that commodity prices will continue to be volatile during 2012. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Significant factors that may impact future commodity prices include the political and economic developments currently impacting Egypt, Libya and the Middle East in general; the extent to which members of the OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas; the impact of sovereign debt issues in Europe; and overall North American oil and natural gas supply and demand fundamentals. Although we cannot predict the occurrence of events that will affect future commodity prices or the degree to which these prices will be affected, the prices for any oil, natural gas or NGLs that we produce will generally approximate market prices in the geographic region of the production.

As an oil and natural gas company, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. Our future growth will depend on our ability to continue to add estimated reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through acquisitions and development projects and improving the economics of producing oil and natural gas from our properties. We expect these acquisition opportunities may come from SEP I and its respective affiliates, as well as from unrelated third parties. Our ability to add estimated reserves through acquisitions and development projects is dependent on many factors, including our ability to raise capital, obtain regulatory approvals and procure contract drilling rigs and personnel.

Results of Operations

As a result of the factors listed above, historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results. In addition, accounting measurements at interim dates inherently involve greater reliance on estimates than at year end and the results for the interim periods are not necessarily indicative of results to be expected for the full year due to several factors, including market conditions, estimates of reserves, drilling risks, geological risks, oil and natural gas supply and demand, market conditions, and potential production interruptions.

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Nine Months Ended September 30, 2011 Compared to the Nine Months Ended September 30, 2010

Revenues. Our oil and natural gas revenues increased by approximately $8.4 million to approximately $9.9 million for the nine month period ended September 30, 2011, as compared to the nine month period ended September 30, 2010. Our total production increased by 475% to approximately 117,700 boe over the same period primarily as the result of the drilling of our first four wells in the Palmetto area and the Alpha Ware #1H well in the Maverick area of the Eagle Ford Shale. Our average realized oil price for the nine months ended September 30, 2011 increased 29% to $92.31 per bo as compared to $71.55 per bo for the period ended September 30, 2010. We had no natural gas production in the 2010 period. The average price realized for our natural gas production in the 2011 period was $4.69 per mcf.

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased by approximately $1.1 million to approximately $1.2 million for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010. The increase in oil and natural gas production expenses for the comparable periods is directly attributable to the increase in production from our increased drilling activities in the Eagle Ford Shale.

Production and Ad Valorem Taxes. Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues sold at market prices or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes increased by approximately $483,000 to approximately $551,000 for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010. The increase in production and ad valorem taxes was due to both the significant increase in production volumes as well as an increase in realized prices for the comparable periods.

Depreciation, Depletion and Amortization. Depletion, depreciation and amortization includes the systematic expensing of the capitalized costs incurred in the acquisition, exploration and development of oil and natural gas. We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration and development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the units of production method based upon production and estimates of proved oil and natural gas reserve quantities. Unproved and unevaluated property costs are excluded from the amortizable base used to determine depletion, depreciation and amortization expense. Our depletion, depreciation and amortization expenses increased by approximately $2.4 million to approximately $2.8 million for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 directly as the result of our increased drilling and increased production volumes.

Impairment of Proved Oil and Natural Gas Properties. If the net capitalized costs of our oil and natural gas properties exceed the estimated present value of future net cash flows from proved oil and natural gas reserves, discounted at 10%, such excess is charged to operations as a full cost ceiling impairment in that reporting period. We did not incur a full cost ceiling impairment for the nine month periods ended September 30, 2011 and 2010.

General and Administrative Expenses. Our general and administrative expenses decreased 15%, or approximately $620,000, to approximately $3.5 million for the nine month period ended September 30, 2011, as compared to the nine month period ended September 30, 2010. The decrease in expense is largely due to efforts undertaken in 2010 to reduce general and administrative expenses, which were realized in the second half of 2010 and during 2011.

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Commodity Derivative Transactions. During the nine months ended September 30, 2011, we had an unrealized gain on our derivative transactions of approximately $1.6 million, as a result of the drop in oil prices since entering into the commodity derivative contract to be contributed to us by SEP I.

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Revenues. Our oil and natural gas revenues increased by approximately $4.3 million to approximately $4.6 million for the year ended December 31, 2010, as compared to the year ended December 31, 2009. Our total production increased by approximately 1,720% to approximately 61,000 boe over the same period primarily as the result of our drilling operations in our Palmetto area of the Eagle Ford Shale. Our average realized oil price for the year ended December 31, 2010, increased 10% to $78.92 per bo as compared to $71.79 per bo for the year ended December 31, 2009. We had no natural gas production in the 2009 period. The average price realized for our natural gas production in the 2011 period was $4.68 per mcf.

Oil and Natural Gas Production Expenses. Our oil and natural gas production expenses increased by approximately $383,000 to approximately $392,000 for the year ended December 31, 2010, as compared to the year ended December 31, 2009. The increase in oil and natural gas production expenses for the comparable periods is directly attributable to the increased in production from our increased drilling activities in the Eagle Ford Shale.

Production and Ad Valorem Taxes. Our production and ad valorem taxes increased by approximately $203,000 to approximately $214,000 for the year ended December 31, 2010, as compared to the year ended December 31, 2009. The increase in production and ad valorem taxes was due to both the significant increase in production volumes as well as an increase in realized prices for the comparable periods.

Depreciation, Depletion and Amortization. Our depletion, depreciation and amortization expenses increased by approximately $1.0 million to approximately $1.4 million for the year ended December 31, 2010, as compared to the year ended December 31, 2009, directly as the result of our increased drilling and increase production volumes.

Impairment of Proved Oil and Natural Gas Properties. We did not incur a full cost ceiling impairment for the year ended December 31, 2010 as compared to an approximately $614,000 impairment for the year ended December 31, 2009.

General and Administrative Expenses. Our general and administrative expenses increased by approximately $3.4 million to approximately $5.3 million for the year ended December 31, 2010 as compared to the year ended December 31, 2009. This increase was attributable to the increase in our activities from primarily leasing of undeveloped acreage to more emphasis on developing the acreage positions through increased drilling activities.

Year Ended December 31, 2009 Compared to the Year Ended December 31, 2008

Our operating activities in 2008 consisted of acquiring undeveloped leases, acquiring seismic data and acquiring other technical data and other expenses associated with those activities, as well as the management of a field office for our unconventional assets. Consequently, we had no revenues in 2008 and an operating loss of approximately $1.2 million directly as a result of the incurred expenses. Our capital expenditures were approximately $14.2 million and they were financed from capital contributions. Our first well was drilled in late 2009, generating approximately $241,000 in total revenue. Those revenues were offset by approximately $2.9 million in operating expenses, consisting primarily of general and administrative expenses of approximately $1.8 million, a full cost ceiling impairment charge of $614,000 and depreciation, depletion and amortization expenses of $415,000. In addition, in 2009 we recorded a gain on the sale of a portion of our undeveloped land position of approximately $2.7 million.

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Liquidity and Capital Resources

Our primary source of liquidity has been capital contributions and our cash flows from operations. We have not used debt financing in the past in connection with acquiring and developing our unconventional assets and have no immediate plans to put in place a credit facility. Our primary uses for our capital have been for the acquisition of leasehold and the exploration and development drilling associated with those undeveloped properties.

On a pro forma basis, after giving effect to this offering and the other transactions described under Prospectus Summary Formation Transactions, we expect to have sufficient liquidity to fund our expected capital expenditure program for the period from January 2012 through December 2013. We currently expect that the net proceeds from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our available liquidity options.

Cash Flows

Our cash flows for the years ended December 31, 2008, 2009 and 2010 and for the nine months ended September 30, 2010 and 2011 are as follows:

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
	(In Thousands)				
Net cash provided by (used in) operating activities	$ (1,247)	$ (1,710)	$ (3,777)	$ (3,140)	$ 2,198
Net cash provided by (used in) investing activities	$ (14,197)	$ 2,734	$ (7,925)	$ (9,101)	$ (10,917)
Net cash provided by (used in) financing activities	$ (15,444)	$ (1,024)	$ 11,702	$ 12,240	$ 8,719

Net Cash Provided by (Used in) Operating Activities. Net cash provided by (used in) operating activities was approximately $(3.1) million and $2.2 million for the nine months ended September 30, 2010 and 2011, respectively. The increase of approximately $5.3 million was largely due to our increased production as a result of the increase in drilling activity. Net cash used in operating activities was approximately $1.7 million and approximately $3.8 million for the twelve months ended December 31, 2009 and 2010, respectively. The decrease was largely due to the increase in general and administrative expenses in 2010 as our activity shifted from mainly leasing to a combination of leasing and drilling.

Net Cash Provided by (Used in) Investing Activities. Our cash flows used in investing activities was approximately $9.1 million and $10.9 million for the nine months ended September 30, 2010 and 2011, respectively. The increase of approximately $1.8 million was largely due to the increase in drilling activities partially offset by the sale of certain non-core undeveloped leases. Net cash provided by (used in) investing activities was approximately $2.7 million and approximately $(7.9) million for the twelve months ended December 31, 2009 and 2010, respectively.

Net Cash Provided by (Used in) Financing Activities. All of our financing activities were provided by capital contributions.

Contractual Obligations

As of December 31, 2010 and September 30, 2011, we had no material contractual obligations.

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Quantitative and Qualitative Disclosure About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and, potentially, interest rates as described below.

The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil and natural gas production. Realized pricing is primarily driven by the spot market prices applicable to our natural gas production and the prevailing price for oil. Pricing for oil and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil and natural gas production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or, through options, modify the future prices realized. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. In addition, we enter into option transactions, such as puts or put spreads, as a way to manage our exposure to fluctuating prices. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

At the closing of this offering, SEP I will contribute to us a commodity derivative contract with a deferred premium cost of approximately $1.9 million covering 1,000 bopd for the 2012 fiscal year. The contract is a put spread where we will be long a $90 oil put and short a $70 oil put. Our put spread protects us from oil prices falling below $90 until such time as prices fall below $70, in which case we receive the market price plus the $20 spread between $90 and $70. SEP I incurred a premium of approximately $1.9 million, which it deferred, at the time of entering into the derivative contract. We will use a portion of the proceeds from this offering to pay the deferred premium amount. As a result, other than the deferred premium obligation, any cash settlements will involve payment from our counterparty to us, with us having no contractual payment obligations to the counterparty.

Interest Rate Risk

We historically have not had any debt and will not have any immediately after this offering. If we incur significant debt in the future we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

Counterparty and Customer Credit Risk

Joint interest receivables arise from entities which own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. Please read Business and Properties Operations Marketing and Major Customers for further detail about our significant customers. Our inability

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or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative contracts expose us to credit risk in the event of nonperformance by counterparties.

Critical Accounting Policies and Estimates

Oil and Natural Gas Properties

We use the full cost method of accounting for oil and natural gas properties. Accordingly, all costs associated with acquisition, exploration, and development of oil and natural gas reserves are capitalized.

Under the full cost accounting rules, capitalized costs, less accumulated amortization, shall not exceed an amount (the ceiling) equal to the sum of: (i) the present value of estimated future net revenues less future production, development, site restoration, and abandonment costs derived based on current costs assuming continuation of existing economic conditions and computed using a discount factor of ten percent; (ii) the cost of properties not being amortized; and (iii) the lower of cost or estimated fair value of unproven properties included in the costs being amortized. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling.

Depreciation, depletion, and amortization is provided using the unit-of-production method based upon estimates of proved oil and natural gas reserves with oil and natural gas production being converted to a common unit of measure based upon their relative energy content. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from amortization are transferred to the full cost pool and amortization begins. The amortizable base includes estimated future development costs and where significant, dismantlement, restoration and abandonment costs, net of estimated salvage value.

In arriving at depletion rates under the unit-of-production method, the quantities of recoverable oil and natural gas reserves are established based on estimates made by our geologists and engineers, which require significant judgment as does the projection of future production volumes and levels of future costs, including future development costs. In addition, considerable judgment is necessary in determining when unproved properties become impaired and in determining the existence of proved reserves once a well has been drilled. All of these judgments may have significant impact on the calculation of depletion and impairment expense. Sales of proved and unproved properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved oil and natural gas reserves, in which case the gain or loss would be recognized in the statement of operations.

Oil and Natural Gas Reserves

In January 2010, the FASB issued an update to the Oil and Gas topic, which aligns the oil and natural gas reserve estimation and disclosure requirements with the requirements in the SEC s final rule, *Modernization of the Oil and Gas Reporting Requirements*, which we refer to as the Final Rule. The Final Rule was issued on December 31, 2008. The Final Rule is intended to provide investors with a more meaningful and comprehensive understanding of oil and natural gas reserves, which should help investors evaluate the relative value of oil and natural gas companies.

The Final Rule permits the use of new technologies to determine proved reserve estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates.

The Final Rule also allows, but does not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC.

In addition, the new disclosure requirements require companies to report oil and natural gas reserves using an average price based upon the prior 12 month period rather than a year-end price. The Final Rule became effective for fiscal years ending on or after December 31, 2009.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The reserve estimates and the projected cash flows derived from these reserve estimates are prepared in accordance with SEC guidelines. The accuracy of our reserve estimates is a function of many factors including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates, all of which could deviate significantly from actual results. As such, reserve estimates may vary materially from the ultimate quantities of oil, natural gas, and natural gas liquids eventually recovered.

Unproved Properties and Impairments

Depreciation, depletion, and amortization is provided using the unit-of-production method based upon estimates of proved oil and natural gas reserves with oil and natural gas production being converted to a common unit of measure based upon their relative energy content. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from amortization are transferred to the full cost pool and amortization begins. The amortizable base includes estimated future development costs and where significant, dismantlement, restoration and abandonment costs, net of estimated salvage value.

Asset Retirement Obligations

We comply with ASC 410-20, to recognize estimated amounts for asset retirement obligations and asset retirement costs. ASC 410-20 requires liability recognition for retirement obligations associated with tangible long-lived assets, such as producing well sites, offshore production platforms, and natural gas processing plants. The obligations included within the scope of ASC 410-20 are those for which a we face a legal obligation for settlement. The initial measurement of the asset retirement obligation is fair value, defined as the price that an entity would have to pay a willing third party of comparable credit standing to assume the liability in a current transaction other than in a forced or liquidation sale. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment, remediation costs, and well life. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which the entity treats as an adjustment to the full cost pool. This standard requires us to record a liability for the fair value of the dismantlement and abandonment costs, excluding salvage values.

Revenue Recognition

Oil and natural gas sales are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred, and collectability of the revenue is probable. Delivery occurs and title is transferred when production has been delivered to a pipeline, railcar or truck, or a tanker lifting has occurred. The sales method of accounting is used for oil and natural gas sales such that revenues are recognized based on our share of actual proceeds from the oil and natural gas sold to purchasers. Oil

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and natural gas imbalances are generated on properties for which two or more owners have the right to take production in-kind and, in doing so, take more or less than their respective entitled percentage.

Derivative Instruments

At times we may utilize derivative instruments to manage our exposure to fluctuations in the underlying commodity prices for the products sold by us. The carrying amount of derivative assets and liabilities is reported on the balance sheet at the estimated fair value of derivative instruments. Our management sets and implements all of our hedging policies, including volumes, types of instruments and counterparties, on a monthly basis. These derivative transactions are not designated as cash flow hedges. Accordingly, these derivative contracts are marked-to-market and any changes in the estimated value of derivative contracts held at the balance sheet date are recognized in the statement of operations as realized and unrealized gains or losses on derivative contracts.

Internal Controls and Procedures

Prior to the completion of this offering, SEP I and SOG have been private companies and have maintained internal controls and procedures in accordance with their status as private companies. We have maintained limited accounting personnel to perform our historical accounting processes and internal control procedures.

We are not currently required to comply with the SEC s rules implementing Section 404 of the Sarbanes-Oxley Act, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC s rules implementing Section 302 of the Sarbanes-Oxley Act, which will require our management to certify financial and other information in our quarterly and annual reports and to provide an annual management report on the effectiveness of our internal control over financial reporting. We will not be required to have our internal control over financial reporting audited until the year following the year that our first annual report is filed or required to be filed with the SEC. To comply with the requirements of being a public company, we will make the necessary upgrades to our information technology system, hire the necessary additional accounting and financial reporting staff, and make the necessary changes to our reporting system and procedures.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2008, 2009 and 2010 and the first nine months of 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the U.S. economy, and we expect to experience inflationary pressure on the cost of oilfield services and equipment when increasing oil and natural gas prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

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BUSINESS AND PROPERTIES

The following Business and Properties discussion should be read in conjunction with Selected Financial Data and the accompanying financial statements and related notes included elsewhere in this prospectus. Unless otherwise indicated, all references to financial or operating data on a pro forma basis give effect to the transactions described under Prospectus Summary Formation Transactions.

Overview

We are an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources and recently formed for the purpose of acquiring unconventional oil and natural gas assets, including those that will be contributed to us as part of the formation transactions. We have accumulated approximately 92,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale in Gonzales, Zavala, Frio, Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. Approximately 54,900 net acres of the 92,000 net acres are attributable to the properties to be acquired as part of the Marquis acquisition. We use the term black oil to describe a quality of oil with an API gravity of 40º or less and with a gas-to-oil ratio of 500 cubic feet per barrel or less. We use the term volatile oil to describe a quality of oil with an API gravity greater than 40º and with a gas-to-oil ratio of greater than 500 cubic feet per barrel. The majority of our capital expenditure budget for the period from January 2012 through December 2013 will be focused on the development and expansion of our oil focused Eagle Ford Shale acreage and operations. We plan to continue to aggressively pursue additional leasehold and strategic acquisitions in the Eagle Ford Shale.

Our management team and the Sanchez Group have a proven track record in identifying, acquiring, and executing large drilling programs and have operated a wide range of drilling projects over the last 40 years, primarily focused as an operator in the South Texas and onshore Gulf Coast areas. Various members of the Sanchez Group have been in the oil and natural gas business since 1972, have drilled or participated in over 900 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry. During this period, they have carefully cultivated their relationships with mineral and surface rights owners in and around our South Texas and onshore Gulf Coast areas, which we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas.

Our Eagle Ford Shale acreage is comprised of approximately 9,400 net acres in Gonzales County, Texas, which we refer to as our Palmetto area, approximately 27,700 net acres in Zavala and Frio Counties, Texas, which we refer to as our Maverick area, and approximately 54,900 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas included in the Marquis acquisition, which we refer to as the Marquis area. Hilcorp recently closed the sale of 141,000 net acres in the Eagle Ford Shale, including its 50% ownership interest in our Palmetto area, to Marathon for approximately $3.5 billion, or an average of $24,822 per net acre, before adjusting for acquired production and reserves and subject to closing adjustments. Marathon is now our 50/50 working interest partner in our Palmetto area, as successor to Hilcorp.

We own all rights and depths on the majority of our Eagle Ford Shale acreage. We believe this acreage to be prospective for other zones, including the Buda Limestone, Austin Chalk and Pearsall Shale formations that lie above and below the Eagle Ford Shale. We are currently evaluating these other zones, which may present us with additional drilling locations. Several of our existing wells are either producing from or have logged pay in the Buda Limestone and the Austin Chalk formations.

In addition, we have approximately 1,250 net acres in the Haynesville Shale in Natchitoches Parish, Louisiana, which are operated by Chesapeake Energy Corporation. We do not currently anticipate spending any capital on our Haynesville acreage in the near future. The majority of our Haynesville leases extend through 2012 and 2013, giving us and our partners the option to accelerate drilling should natural gas prices increase. Finally, we have amassed approximately 82,000 net acres in northern Montana, which we believe may be prospective for the Heath, Three Forks and Bakken Shales.

The following table presents summary data for each of our primary project areas as of September 30, 2011, unless otherwise indicated:

				Capital Expenditure Budget from January 2012 through December 2013			
	Net Acreage	Identified Drilling Locations[1] Gross	Net	Gross Wells	Net Wells	Drilling Capex (In millions)	Estimated Net Proved Reserves[2] (mmboe)
Palmetto Gonzales[3]	9,392	156	76	39	19	$ 165	2.9
Maverick Zavala, Frio	27,711	285	230	18	9	50	0.1
Marquis Fayette, Lavaca, Atascosa, Webb and DeWitt	54,868	457	457	18	18	135	-
Total Eagle Ford Shale	91,971	898	763	75	46	$ 350	3.0
Haynesville Shale	1,252	60	15	-	-	-	0.2
Heath, Three Forks and Bakken Shales	82,274	-	-	-	-	-	-
Total	175,497	958	778	75	46	$ 350	3.2

(1) Total identified drilling locations are calculated using approximately 120 acre spacing in our Eagle Ford Shale areas and approximately 80 acre spacing in our Haynesville Shale area on the undeveloped portion of our acreage. We are currently evaluating our acreage in the Heath, Three Forks and Bakken Shales and have not identified any drilling locations on that acreage.

(2) Based on Ryder Scott estimated proved reserve report as of June 30, 2011.

(3) In our Palmetto area, we have 19 gross (9.5 net) locations that are classified as proved undeveloped at June 30, 2011. We plan to drill all of those proved undeveloped locations within the next five years.

The table above identifies a total of up to 958 gross (778 net) drilling locations, of which over 90% are located in our Eagle Ford Shale acreage position. Our Ryder Scott estimated proved reserve report dated as of June 30, 2011 attributed proved undeveloped reserves to 20 gross locations of these total identified locations, one of which was placed on production subsequent to June 30, 2011. In addition, this reserve report attributed probable undeveloped reserves to 84 gross locations and possible undeveloped reserves to 75 gross locations.

Capital Expenditure Budget from January 2012 through December 2013

Our capital expenditure budget for the period from January 2012 through December 2013 is approximately $413 million, and is anticipated to consist of the following:

Approximately $350 million for drilling and completing wells in the Eagle Ford Shale; and

Approximately $50 million for expansion of our Eagle Ford Shale acreage position.

Approximately $13 million for construction of central facilities for our Eagle Ford Shale acreage.

While we have budgeted $413 million in our capital expenditure budget for the period from January 2012 through December 2013, the ultimate amount and allocation of capital spent could vary. We will evaluate market conditions in each of our operating areas to determine the estimated economic returns on capital employed. If those returns exceed or fall short of our thresholds, our capital expenditures and allocations could change accordingly.

Our Business Strategies

Our primary business objective is to increase stockholder value by building reserves, production and cash flows at an attractive return on invested capital. To achieve our objective, we intend to execute the following business strategies:

Aggressively Develop Our Eagle Ford Shale Leasehold Positions. We intend to aggressively drill and develop our acreage position to maximize the value of our resource potential. The up to 898 gross (763 net) locations for potential future drilling that we have identified in our Eagle Ford Shale area will be our primary targets in the near term as we believe the Eagle Ford Shale to be the highest rate of return project that we currently possess. We anticipate drilling 75 gross (46 net) wells through December 2013 with an aggregate drilling and completion capital expenditure budget of approximately $350 million.

Pursue Strategic Acquisitions and Grow Our Leasehold Position in the Eagle Ford Shale and Seek Entry into New Basins. We believe that we will be able to identify and acquire additional

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acreage and producing assets in the Eagle Ford Shale. We recently entered into a definitive agreement to acquire approximately 54,900 net acres from Ross Exploration for approximately $89 million in cash, subject to adjustment, 909,091 shares of our common stock and a previously conveyed overriding royalty interest in what is now our Marquis area. By leveraging our longstanding relationships in South Texas, we plan on continuing to expand our Eagle Ford Shale acreage position at what we believe to be attractive valuations, and we have budgeted $50 million for additional leasehold acquisitions in the Eagle Ford Shale for the period between January 2012 and December 2013. We also plan to selectively target additional domestic basins that would allow us to employ our strategies on large undeveloped acreage positions similar to our Eagle Ford Shale acreage.

Leverage our Relationship with Our Affiliates to Expand Unconventional Oil Assets. Our largest stockholder is controlled by certain members of the Sanchez Group. Various members of the Sanchez Group have drilled or participated in over 900 wells, directly and through joint ventures, and have invested substantial amounts of capital in the oil and natural gas industry since 1972. During this period, they have carefully cultivated their relationships with mineral and surface rights owners in and around our South Texas and onshore Gulf Coast areas and compiled an extensive technological database, which we believe gives us a competitive advantage in acquiring additional leasehold positions in these areas. We will have access to the unrestricted, proprietary portions of the technological database related to our properties, and SOG will otherwise be required to interpret and use the database, to the extent relating to our properties for our benefit. The majority of the database covers the South Texas and onshore Gulf Coast areas and includes more than 6,400 square miles of 3D seismic data and 48,000 miles of 2D seismic data used for regional interpretation, 395,000 well logs, 13,000 LAS files and 30,000 scanned well documents, as well as a fully integrated suite of the latest interpretive geologic software. We plan on leveraging our affiliates expertise, industry relationships and size to opportunistically expand reserves and our leasehold positions in the Eagle Ford Shale and other onshore unconventional oil resources.

Enhance Returns by Focusing on Operational and Cost Efficiencies. We are focused on continuous improvement of our operating measures and have significant experience in successfully converting early-stage resource opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our project areas provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad, utilizing centralized production and fluid handling facilities and reducing the time and cost of rig mobilization.

Adopt and Employ Leading Drilling and Completion Techniques. We are focused on enhancing our drilling and completion techniques to maximize recovery. Industry techniques with respect to drilling and completion have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of longer laterals and more tightly spaced fracturing stimulation stages. We continuously evaluate industry drilling results and monitor the results of other operators to improve our operating practices, and we expect our drilling and completion techniques will continue to evolve.

Maintain Substantial Financial Liquidity to Capitalize on Opportunity and Limit Commodity Price Volatility. Following the completion of this offering and the other transactions described under Prospectus Summary Formation Transactions, we will have approximately $64 million in cash and no outstanding indebtedness. We believe this strong liquidity position will allow us to grow production and proved reserves, to capitalize on acreage acquisition opportunities and to weather any potential volatility in commodity prices. We currently expect that the net proceeds from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our available liquidity options.

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Our Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies:

Geographically Concentrated Leasehold Position in One of North America s Leading Unconventional Oil Resource Trends. We have assembled a current leasehold position of approximately 92,000 net leasehold acres in the Eagle Ford Shale, which we believe to be one of the highest rates of return unconventional oil and natural gas areas in North America. Our geographically concentrated acreage position allows us to establish economies of scale with respect to drilling, production, operating and administrative costs in addition to further leveraging our base of technical expertise in our project areas. We believe that offset operator activity and well results around our project areas have significantly de-risked our acreage positions such that we believe that there are low geologic risks and drilling opportunities across our acreage positions.

Large, Multi-Year Inventory. We have an inventory of up to 898 gross (763 net) locations for potential future drilling on our Eagle Ford Shale acreage position and 60 gross (15 net) locations for potential future drilling on our Haynesville acreage position. For the period from January 2012 through December 2013, we plan on drilling 75 gross (46 net) wells on our Eagle Ford Shale acreage. The drilling and completion of these wells would represent approximately 8% of the total gross identified locations and approximately 6% of the total net identified locations on our Eagle Ford Shale acreage. As the industry continues to refine drilling and completion technologies, we may be able to enhance total recovery and inventory through the drilling of in-fill locations on our acreage positions. In addition, we have amassed approximately 82,000 net acres in Lewis and Clark, Meagher, and Cascade Counties of Montana that we believe may be prospective for the Heath, Three Forks and Bakken Shales. If we are successful in developing this acreage, we could materially expand our multi-year inventory.

Our Relationship with Members of the Sanchez Group and Our Services Agreement Provide us with Extensive Technical Expertise and Access to Long Standing Relationships with Mineral Owners. Certain members of the Sanchez Group have been in the oil and natural gas business since 1972 and have drilled or participated in over 900 wells, directly and through joint ventures, in and around our South Texas and onshore Gulf Coast areas. This long operating history in the basins in which we operate provides us with extensive knowledge of the basins and the ability to leverage longstanding relationships with mineral owners. We believe that this expertise and these relationships, together with our services agreement, should allow us to develop our assets efficiently and increase our acreage position.

Significant Financial Flexibility. We have no outstanding indebtedness and following the completion of this offering and the other transactions described under Prospectus Summary Formation Transactions, we will have approximately $64 million in cash and no outstanding indebtedness. We will use this cash to fund our capital expenditures, and, in particular, our drilling, exploration and acquisition programs through December 2013, our other operating expenses, and for general corporate purposes. We currently expect that the net proceeds from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our available liquidity options.

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Properties

Eagle Ford Shale

The Eagle Ford Shale is one of the fastest growing unconventional shale trends in North America. According to the Smith Weekly Rig Count, since January 2010, the rig count in the Eagle Ford Shale has grown 659% from 27 rigs to 205 rigs as of November 11, 2011. Based on a recent study by the Society of Petroleum Engineers, the aerial extent of the trend is thought to be approximately 11 million acres.

The Eagle Ford Shale is a geological formation located in South Texas that lies directly beneath the Austin Chalk formation and above the Buda Limestone formation. It is considered to be the source rock, or the original source of hydrocarbons that are contained in the Austin Chalk formation. The Eagle Ford Shale produces from various depths between 4,000 and 14,000 feet. The Eagle Ford Shale has a carbonate content as high as 70%, which makes it more similar to a traditional carbonate than to a shale. The high carbonate content and subsequently lower clay content make the Eagle Ford Shale more brittle and easier to stimulate through hydraulic fracturing. The Eagle Ford Shale formation has an average organic content of 4.25% and has an average core-measured porosity of 9%.

In geological terms, the Eagle Ford Shale dips toward the Gulf of Mexico and is up to 300 feet thick in some areas, but averages 250 feet across the trend. Thermal maturity is impacted by the location and depth of the shale across the trend. Generally in shallower areas the Eagle Ford Shale is less thermally mature and therefore tends to be more oil prone. We refer to this area as the black oil window and our Maverick area in Zavala and Frio Counties, Texas are situated within this window. The deeper, more thermally mature, areas of the Eagle Ford Shale are more gas prone. Areas in between, like our Palmetto area in Gonzales County, Texas tend to have a high NGLs content and are often referred to as the volatile oil window.

Most of the current Eagle Ford Shale activity is concentrated in Atascosa, Bee, DeWitt, Dimmit, Fayette, Frio, Gonzales, Karnes, LaSalle, Lavaca, Live Oak, Maverick, McMullen, Webb, Wilson and Zavala Counties in South Texas. The first horizontal wells drilled specifically for the Eagle Ford Shale were drilled in 2008, leading to a discovery in LaSalle County. Since then, the trend has expanded significantly across a large portion of South Texas.

Public information indicates that operators are typically drilling 3,500 to 7,000 feet horizontal laterals and applying hydraulic fracture stimulation in multiple stages along the full length of the horizontal laterals to complete the wells and establish production. Based on publicly available information, we believe that average drilling and completion costs in the trend have ranged between $5.5 million and $9.5 million per well with average EURs ranging from 225,000 to 850,000 boe per well, and initial 30-day average production has ranged between 200 to 2,000 boe/d per well. There have been a number of recent publicly-reported transactions in the trend that have yielded average per acre valuations ranging from approximately $5,000 per acre to $25,000 per acre. Based on our experience and that of other companies operating in this trend, we believe that the Eagle Ford Shale can be characterized as having low geologic risks and repeatable drilling opportunities.

In the Eagle Ford Shale, we have assembled approximately 92,000 net acres with an average working interest of approximately 85%. Using approximately 120 acre well-spacing for horizontal well development, we believe that there could be up to 898 gross and (763 net) locations for potential future drilling on our acreage. Consistent with other operators in this area, we plan to perform multi-stage hydraulic fracturing with 12 to 20 stages on each lateral well. For the period from January 2012 through December 2013, we plan to spend approximately $350 million on drilling 75 gross (46 net) wells on our Eagle Ford Shale acreage.

In our Palmetto area, we have approximately 9,400 net acres in Gonzales County, Texas with an average working interest of approximately 49%. Hilcorp recently closed its sale of 141,000 net acres in Gonzales, Atascosa and Karnes Counties in the Eagle Ford Shale to Marathon for approximately $3.5 billion, or an average of $24,822 per net acre, before adjusting for acquired production and reserves. Marathon is now our 50% working interest

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partner on our Palmetto acreage. We believe that our Palmetto acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $7.5 million and $9.5 million per well based on publicly available information. We have participated in the drilling of four gross wells on our acreage that had an average initial 30-day per well choke restricted production rate of 788 boe/d (665 bopd and 737 mcf/d). Marathon, as the successor to Hilcorp s working interest, has expressed to us a desire to accelerate drilling in our Palmetto area in 2012. We have identified up to 156 gross (76 net) locations based on 120 acre spacing for potential future drilling in our Palmetto area. For the period from January 2012 through December 2013, we plan to spend approximately $165 million to drill 39 gross (19 net) wells in our Palmetto area.

In February 2011, we completed our fourth Eagle Ford horizontal well in our Palmetto area, the Barnhart #4H, in Gonzales County, Texas. This well was a 5,507 foot lateral well and was completed using a 16 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 893 boe/d (713 bopd and 1,080 mcf/d) using a 15/64 inch restricted choke. Through October 10, 2011, the Barnhart #4H has produced a total of approximately 153,066 boe (115,815 bo and 223,507 mcf). We have a 50% working interest in the well.

In November 2010, we completed our third Eagle Ford horizontal well in our Palmetto area, the Barnhart #3H, in Gonzales County, Texas. This well was a 5,320 foot lateral well and was completed using a 16 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 663 boe/d (618 bopd and 271 mcf/d) using a 15/64 inch restricted choke. Through October 10, 2011, the Barnhart #3H has produced a total of approximately 99,843 boe (94,510 bo and 31,995 mcf). We have a 50% working interest in the well.

In October 2010, we completed our second Eagle Ford horizontal well in our Palmetto area, the Barnhart #2H, in Gonzales County, Texas. This well was a 5,100 foot lateral well and was completed using a 12 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 1,102 boe/d (880 bopd and 1,330 mcf/d) using a 13/64 inch restricted choke. Through October 10, 2011, the Barnhart #2H has produced a total of approximately 153,268 boe (117,945 bo and 211,935 mcf). We have a 50% working interest in the well.

In July 2010, we completed our first Eagle Ford horizontal well in our Palmetto area, the Barnhart #1H, in Gonzales County, Texas. This well was a 3,902 foot lateral well and was completed using a 12 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 491 boe/d (447 bopd and 268 mcf/d) using a 17/64 inch restricted choke. Through October 10, 2011, the Barnhart #1H has produced a total of approximately 77,504 boe (66,856 bo and 63,886 mcf). We have a 50% working interest in the well.

In our Maverick area, we have approximately 27,700 net operated acres in Zavala and Frio Counties, Texas with an average working interest of approximately 81%. We believe that our Maverick acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 million and $6.5 million per well based on publicly available information. We have identified up to 285 gross (230 net) locations based on 120 acre spacing for potential future drilling on our Maverick acreage. We have drilled one horizontal well that had an initial 30-day average production rate of 242 bopd. We are currently drilling one vertical well to also test the feasibility of a vertical development program and compare horizontal and vertical completion economic returns. For the period from January 2012 through December 2013, we plan to spend approximately $50 million to drill 18 gross (9 net) wells in our Maverick area.

In July 2011, we completed our first Maverick area Eagle Ford horizontal well, the Alpha Ware #1H, in Zavala County, Texas. This well was a 6,513 foot lateral well and was completed using a 20 stage hydraulic fracture stimulation. The 30-day average initial production rate from this well was 242 bopd. Through October 10, 2011, the Alpha Ware #1H has produced a total of approximately 14,262 bo. We are the operator of the well and have a 60% working interest in the well.

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In our Marquis area, we have approximately 54,900 net operated acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We believe that our Marquis acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $6.5 million and $8.5 million per well based on publicly available information. We have identified up to 457 gross and net locations based on 120 acre spacing for potential future drilling on our Marquis acreage. Other operators in this project area have recently reported initial per well production rates of 1,000 to 1,200 boe/d. For the period from January 2012 through December 2013, we plan to spend approximately $135 million to drill 18 gross (18 net) wells in our Marquis area. Our net acreage, the number of identified drilling locations and wells, and capital expenditures are presented throughout this prospectus after giving effect to the Marquis acquisition.

Haynesville Shale

The Haynesville Shale is a geologic formation located in northwest Louisiana and East Texas that lies below the Cotton Valley and Bossier formations and above the Smackover formation. The Haynesville Shale produces from various depths between 10,500 to 13,500 feet. Sub-surface, the formation dips southward toward the Gulf of Mexico and is found deeper the further south wells are drilled. The Haynesville Shale s porosity is often higher than other shales with an average core-measured porosity of 8.5%. The Haynesville Shale has a typical thickness ranging from 200 to 300 feet and an average organic content of 2.25%. The Haynesville Shale produces primarily dry natural gas with almost no associated liquids.

The trend has seen significant drilling activity over the last several years with the most activity focused in Bossier, Caddo, DeSoto, Natchitoches, and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. Operators are typically drilling 4,500 to 5,000 feet horizontal laterals and applying hydraulic fracture stimulation in multiple stages along the entire length of the horizontal laterals to complete the wells and establish production. Although production rates vary widely across the trend, in the core area of the trend, initial production rates of 20.0 to 25.0 mmcf per day of natural gas have been reported by operators.

We have assembled approximately 1,250 net acres in Natchitoches Parish, Louisiana that are prospective for the Haynesville Shale. We have an average working interest of approximately 25% and the operator on our Haynesville Shale acreage is Chesapeake Energy Corporation. Three gross wells have been drilled to date, and we have participated in one of those wells. The one well (32% working interest) went on production in October 2011 and was tested on an initial choke restricted production rate of 9 mmcf/d. We believe that our acreage position is in the core of the Haynesville Shale fairway. We anticipate drilling, completion and facilities costs on our acreage to be between $8.0 and $10.0 million per well. We have identified 60 gross and 15 net locations for potential future drilling on our acreage. We do not currently anticipate spending any capital on our Haynesville Shale acreage in the near term. The majority of our Haynesville Shale leases extend through 2012 and 2013, giving us and our partners the option to accelerate drilling should natural gas prices increase.

Heath, Three Forks and Bakken Shales

We have acquired approximately 82,000 net acres in Lewis and Clark, Meagher, and Cascade Counties of Montana that we believe may be prospective for the Heath, Three Forks and Bakken Shales. We plan to monitor industry activity in our area as we develop our plans. Our lease terms are for five years with an option to renew for another five years at $10 per acre, giving us time to allow industry activity to develop the trend before we devote significant drilling capital to our acreage position.

Recent Developments

On November 8, 2011, we entered into the Marquis Contribution Agreement with Ross Exploration to acquire Marquis LLC, which owns a 100% working interest and an approximate 75% net revenue interest in approximately 54,900 net acres in Fayette, Lavaca, Atascosa, Webb and DeWitt Counties of South Texas. We have agreed to pay Ross Exploration approximately $89 million in cash, subject to customary pre- and post-closing adjustments (and exclusive of certain costs and expenses for which we have agreed to reimburse Ross

Exploration in cash at closing), and 909,091 shares of our common stock. The acreage that we are acquiring is subject to an overriding royalty interest that was previously conveyed by Ross Exploration to an affiliate as part of the transactions contemplated by the Marquis Contribution Agreement. Approximately 48,600 net acres are located in what we believe to be the volatile oil window of the Eagle Ford Shale in southwest Fayette and northeast Lavaca Counties, Texas. For the period from January 2012 through December 2013, we plan to spend approximately $135 million to drill 18 gross (18 net) wells in our Marquis area. See The Marquis Acquisition for additional information.

Since the end of the third quarter of 2011, we have drilled our fifth and sixth Eagle Ford Shale horizontal wells in our Palmetto area, the Barnhart #5H and #6H, in Gonzales County, Texas. We recently finished completion activities on these two wells and they commenced production in December 2011. The initial 24-hour production rates for the Barnhart #5H and #6H were 1,435 boe/d and 1,382 boe/d, respectively, using a 14/64 inch restricted choke.

Oil and Natural Gas Reserves and Production

Internal Controls

Our estimated reserves at December 31, 2010 and June 30, 2011 were prepared by Ryder Scott, our independent reserve engineers. Following the completion of this offering, we expect to have our reserve estimates prepared by our independent third-party reserve engineers, Ryder Scott, at least annually. Our internal professional staff works closely with Ryder Scott to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, we provide Ryder Scott other pertinent data, such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves.

Technology Used to Establish Reserves

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

To establish reasonable certainty with respect to our estimated proved reserves, Ryder Scott employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques.

See Estimated Probable and Possible Reserves for additional information regarding probable and possible reserves.

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Qualifications of Responsible Technical Persons

Internal SOG Person. Vinodh Kumar is the technical person primarily responsible for overseeing the preparation of our reserve estimates.

Mr. Kumar is also responsible for liaison with and oversight of our third-party reserve engineers. Mr. Kumar has over 40 years of industry experience with positions of increasing responsibility in engineering and evaluations with companies such as Hilcorp Energy Company, El Paso Exploration & Production Company, KCS Energy, Inc. and Koch Industries, Inc. He holds a Masters of Science degree in Petroleum Engineering from the University of Calgary and a Masters of Business Administration from Wichita State University, and he is a Registered Professional Engineer in the State of Texas.

Ryder Scott. Ryder Scott is an independent oil and natural gas consulting firm. No director, officer or key employee of Ryder Scott has any financial ownership in any member of the Sanchez Group or us. Ryder Scott s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Ryder Scott has not performed other work for SOG, SEP I or us that would affect its objectivity. The engineering information presented in Ryder Scott s report was overseen by Don P. Griffin P.E. Mr. Griffin is an experienced reservoir engineer having been a practicing petroleum engineer since 1976. He has more than 30 years of experience in reserves evaluation with Ryder Scott. He has a Bachelor of Science degree in Electrical Engineering from Texas Tech University and is a Registered Professional Engineer in the State of Texas.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to our properties and the standardized measure amounts associated with the estimated proved reserves attributable to our properties as of December 31, 2010 and June 30, 2011, based on reserve reports prepared by Ryder Scott, our independent reserve engineers. The standardized measure amounts shown in the table are not intended to represent the current market value of our estimated oil and natural gas reserves.

	As of December 31, 2010	As of June 30, 2011
Reserve Data(l):		
Estimated proved reserves:		
Oil (mbo)	2,631.0	2,596.1
Natural gas (mmcf)	2,652.5	3,889.3
Total estimated proved reserves (mboe)(2)	3,073.1	3,244.3
Estimated proved developed reserves:		
Oil (mbo)	362.0	356.6
Natural gas (mmcf)	1,540.7	1,741.4
Total estimated proved developed reserves (mboe)(2)	618.8	646.9
Estimated proved undeveloped reserves:		
Oil (mbo)	2,269.0	2,239.5
Natural gas (mmcf)	1,111.8	2,147.9
Total estimated proved undeveloped reserves (mboe)(2)	2,454.3	2,597.5
Standardized Measure (in millions)(3)	$ 50.7	$ 69.5

(1) Our estimated net proved reserves and related standardized measure were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of our properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $79.43/bo for oil and $4.38/mmbtu for natural gas at December 31, 2010 and $90.09/bo for oil and $4.21/mmbtu for natural gas at June 30, 2011. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead. As of December 31, 2010, the average realized prices for oil and natural gas were $78.92 per bo and $4.68 per mcf, respectively. As of June 30, 2011, the relevant average realized prices for oil and natural gas were $94.75 per bo, $4.66 per mcf, respectively.

(2) One boe is equal to six mcf of natural gas or one bo of oil or NGL s based on a rough energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

(3) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, Extractive Activities Oil and Gas. For a description of our expected commodity derivative contracts, please read Management s Discussion and Analysis of Financial Condition and Results of Operations Overview Realized Prices on the Sale of Oil and Natural Gas Commodity Derivative Contracts. Prior to the closing of this offering, we will not be treated as a taxable entity for federal income tax purposes. Future calculation of the standardized measure will include the effects of income taxes on future net revenues. For further discussion of income taxes, see Management s Discussion and Analysis of Financial Condition and Results of Operations. For further information regarding the calculation of the standardized measure (and the effect of income taxes), see Unaudited Supplementary Information included in the financial statements elsewhere in this prospectus.

The data in the table above represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. For a discussion of risks associated with internal reserve estimates, please read Risk Factors Risks Related to Our Business Our estimated reserves and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

Future prices realized for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure amounts shown above should not be construed as the current market value of our estimated oil and natural gas reserves. The 10% discount factor used to calculate standardized measure, which is required by Financial Accounting Standard Board pronouncements, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

Development of Proved Undeveloped Reserves

None of our proved undeveloped reserves at June 30, 2011 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. In early 2010, we commenced the development of our Palmetto area and, during the course of that year, we drilled and completed three gross wells, the Barnett #1H, Barnett #2H and Barnett #3H, across our acreage in order to assess and begin the delineation of the area. All three of those wells were successful, resulting in the booking of substantial proved undeveloped reserves at December 31, 2010. We had no proved undeveloped reserves in 2009 and, as a result, the amount of proved undeveloped reserves increased substantially year over year, from zero in 2009 to 2.5 million boe in 2010. Historically, our drilling and development programs were substantially funded from capital contributions and our cash flow from operations. Our expectation is to continue to fund our drilling and development programs primarily from equity capital, including a portion of the net proceeds from this offering and our cash flow from operations. Based on our current expectations of our cash flows and drilling and development programs, which includes drilling of proved undeveloped locations, we believe that we can fund the drilling of our current inventory of proved undeveloped locations and our expansions, extensions in the next five years from our cash flow from operations and, if needed, through additional equity capital and any credit facility we may enter into. We currently expect that the net proceeds from this offering and our expected cash flows from operations will not require us to obtain any material debt financing to finance our planned capital expenditure program through December 2013. However, we anticipate that we will arrange a borrowing facility in the future to increase our available liquidity options. For a more detailed discussion of our liquidity position, please read

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Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

For more information about SEP I s historical costs associated with the development of proved undeveloped reserves, please read the Unaudited Supplementary Information included in the financial statements elsewhere in this prospectus.

Estimated Probable and Possible Reserves

Unless otherwise specifically identified in this prospectus, the summary data with respect to our estimated reserves has been prepared by our independent reserve engineers in accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities.

The reserve estimates at December 31, 2010 and June 30, 2011 presented in the table below are based on reports prepared by Ryder Scott, independent reserve engineers. For more information regarding our independent reserve engineers, please see Qualifications of Responsible Technical Persons above. The information in the following table does not give any effect to or reflect our commodity derivative instruments.

Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with

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displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

	At December 31, 2010(2)						At June 30, 2011(2)					
	Proved Reserves (mboe)(5)	PV-10(3) (in millions)	Probable Reserves(4) (mboe)(5)	PV-10(3) (in millions)	Possible Reserves(4) (mboe)(5)	PV-10(3) (in millions)	Proved Reserves (mboe)(5)	PV-10(3) (in millions)	Probable Reserves(4) (mboe)(5)	PV-10(3) (in millions)	Possible Reserves(4) (mboe)(5)	PV-10(3) (in millions)
Project Area(1)												
Eagle Ford												
Palmetto-Gonzales	2,870	$ 47.2	11,428	$ 154.6	8,147	$ 60.2	2,939	$ 61.2	11,428	$ 200.5	8,148	$ 80.7
Maverick-Zavala, Frio	5	0.1	N/A	N/A	N/A	N/A	107	5.0	1,523	16.6	-	-
Total Eagle Ford	2,875	$ 47.3	11,428	$ 154.6	8,147	$ 60.2	3,046	$ 66.2	12,951	$ 217.1	8,148	$ 80.7
Haynesville	197	3.4	N/A	N/A	N/A	N/A	199	3.3	N/A	N/A	N/A	N/A
Total	3,072	$ 50.7	11,428	$ 154.6	8,147	$ 60.2	3,245	$ 69.5	12,951	$ 217.1	8,148	$ 80.7

(1) Excludes our Marquis area, which has no estimated proved, probable or possible reserves.

(2) Our estimated net proved, probable and possible reserves and related future net revenues and PV-10 at December 31, 2010 and June 30, 2011 were determined using index prices for oil and natural gas, without giving effect to commodity derivative contracts, held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $79.43/bo for oil and $4.38/mmbtu for natural gas at December 31, 2010 and $90.09/bo for oil and $4.21/mmbtu for natural gas at June 30, 2011. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price realized at the wellhead. As of December 31, 2010, the average realized prices for oil and natural gas were $78.92 per bo and $4.68 per mcf, respectively. As of June 30, 2011, the average realized prices for oil and natural gas were $94.75 per bo and $4.66 per mcf, respectively.

(3) PV-10 is a non-GAAP financial measure and represents the period-end present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 for probable and possible reserves is not comparable to PV-10 for proved reserves and you should not consider these measures as equivalent or place undue reliance on PV-10 for probable and possible reserves. PV-10 differs from standardized measure because it does not include the effects of income taxes. Our PV-10 and our standardized measure are equivalent because prior to completion of this offering we were not subject to entity level taxation. Accordingly, no provision for federal income taxes has been provided because taxable income is passed through to our equity holder. After this offering we will be treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

(4) In addition to estimated proved reserve reports dated December 31, 2010 and June 30, 2011, Ryder Scott provided us with probable and possible reserve reports as of June 30, 2011 for the Maverick area and as of December 31, 2010 and June 30, 2011 for the Palmetto area. Probable and possible reserves included in the report as of June 30, 2011 totaled 21 mmboe and $297.8 million in additional PV-10 value. Of these June 30, 2011 reserves, 93% were attributed to our Palmetto area and 7% were attributed to our Maverick area. As of December 31, 2010, of these probable and possible reserves, 9,416 and 7,818 mbo were classified as oil, 12,072 mmcf and 1,974 mmcf were classified as natural gas and none were classified as NGLs, respectively. As of June 30, 2011, of these probable and possible reserves, 10,824 and 7,818 mbo were classified as oil, 12,762 mmcf and 1,973 mmcf were classified as natural gas and none were classified as NGLs, respectively. Estimates of probable and possible reserves that may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. All of our probable and possible reserves are classified as undeveloped.

(5) One boe is equal to six mcf of natural gas or one bo of oil or NGL s based on a rough energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.

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Production, Revenues and Price History

The following table sets forth information regarding combined net production of oil and natural gas and certain price and cost information attributable to our properties for each of the periods presented:

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
Production and operating data:					
Net production volumes:(1)					
Oil (mbo)	-	3.4	55.8	20.5	102.2
Natural gas (mmcf)	-	-	31.9	-	93.0
Total (mboe)	-	3.4	61.1	20.5	117.7
Average net production (boe/d)	-	9.2	167.4	75.0	431.1
Average sales price:(2)					
Oil (per bo)	$ -	$ 71.79	$ 78.92	$ 71.55	$ 92.31
Natural gas (per mcf)	$ -	$ -	$ 4.68	$ -	$ 4.69
Average price per boe	$ -	$ 71.79	$ 74.50	$ 71.55	$ 83.85
Average unit costs per boe:					
Oil and natural gas production expenses	$ -	$ 2.50	$ 6.41	$ 3.44	$ 10.27
Production taxes	$ -	$ 3.31	$ 3.50	$ 3.30	$ 4.68
General and administrative	$ -	$ 545.60	$ 86.32	$ 201.29	$ 29.77
Depletion, depreciation and amortization	$ -	$ 123.65	$ 23.36	$ 15.80	$ 23.46

(1) Our Palmetto area constituted approximately 90.6% of our estimated proved reserves as of June 30, 2011. Our production from the Palmetto area was 48.5 mboe for the year ended December 31, 2010. We had no production in our Palmetto area in 2008 and 2009. The 2010 production was comprised of 43.2 mbo of oil, 31.9 mmcf of natural gas and no NGLs.

(2) Prices do not include the effects of derivative cash settlements.

Drilling Activities

The following table sets forth information with respect to wells drilled and completed during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2008		2009		2010	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	-					