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

# FORM 10-K

**(Mark One)**

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

**For the fiscal year ended December 31, 2011**

**OR**

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

**For the transition period from________ to ________**

**Commission file number: 1-32167**

# VAALCO Energy, Inc.

**(Exact name of registrant as specified on its charter)**

| | |
|---|---|
| **Delaware** | **76-0274813** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification No.)** |

**4600 Post Oak Place**
**Suite 300**
**Houston, Texas 77027**
**(Address of principal executive offices) (Zip Code)**

**(Registrant's telephone number, including area code): (713) 623-0801**

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

| Title of each class | Name of exchange on which registered |
|---|---|
| Common Stock, $.10 par value | New York Stock Exchange |

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

**None**

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

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

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

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

Large accelerated filer __ Accelerated filer X Non-accelerated filer __ Smaller reporting company __

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, as of June 30, 2011 was $343,384,364 based on a closing price of $6.02 on June 30, 2011.

As of February 29, 2012, there were outstanding 57,118,925 shares of common stock, $0.10 par value per share, of the registrant.

Documents incorporated by reference: Definitive proxy statement of VAALCO Energy, Inc. relating to the Annual Meeting of Stockholders to be filed within 120 days after the end of the fiscal year covered by this Form 10-K, which is incorporated into Part III of this Form 10-K.

**VAALCO ENERGY, INC.**

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## Glossary of Oil and Gas Terms

**Terms used to describe quantities of oil and natural gas**

- Bbl—One stock tank barrel, or 42 US gallons liquid volume, of crude oil or other liquid hydrocarbons.
- BOE—One barrel of oil equivalent, converting gas to oil at the ratio of 6 Mcf of gas to 1 Bbl of oil. The ratio of six Mcf of natural gas to one Bbl of oil or natural gas liquids is commonly used in the oil and gas business and represents the approximate energy equivalency of six Mcf of natural gas to one Bbl of oil or liquids, and does not represent the sales price equivalency of natural gas to oil or liquids. Currently, the sales price of Bbl of oil or natural gas liquids is significantly higher than the sales price of six Mcf of natural gas.
- BOPD—One barrel of oil per day.
- MBbl—One thousand Bbls.
- Mcf—One thousand cubic feet of natural gas.
- MMcf—One million cubic feet of natural gas.

**Terms used to describe the Company's interests in wells and acreage**

- Gross oil and gas wells or acres—The Company's gross wells or gross acres represent the total number of wells or acres in which the Company owns a working interest.
- Net oil and gas wells or acres—Determined by multiplying "gross" oil and natural gas wells or acres by the working interest that the Company owns in such wells or acres represented by the underlying properties.

**Terms used to assign a present value to the Company's reserves**

- Standard measure of proved reserves—The present value, discounted at 10%, of the pre-United States income tax future net cash flows attributable to estimated net proved reserves. The Company calculates this amount by assuming that it will sell the oil and gas production attributable to the proved reserves estimated in its independent engineer's reserve report for the prices used in the report, unless it had a contract to sell the production for a different price. The Company also assumes that the cost to produce the reserves will remain constant at the costs prevailing on the date of the report. The assumed costs are subtracted from the assumed revenues resulting in a stream of future net cash flows. Estimated future income taxes using rates in effect on the date of the report are deducted from the net cash flow stream. The after-tax cash flows are discounted at 10% to result in the standardized measure of the Company's proved reserves.

**Terms used to classify the Company's reserve quantities**

- *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

    (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

    (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

- *Proved oil and gas reserves*. Proved oil and gas reserves are those quantities of oil and gas, which, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- *Reserves*. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

- *Standardized measure*. 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 Securities and Exchange Commission, using prices and costs in effect as of the date of estimation, without giving effect to non–property related expenses such as certain general and administrative expenses, debt service and future federal income tax expenses or to depreciation, depletion and amortization and discounted using an annual discount rate of 10%.

- *Undeveloped oil and gas reserves*. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
  - (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
  - (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
  - (iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
- *Unproved properties.* Properties with no proved reserves.

**Terms which describe the productive life of a property or group of properties**

- *Reserve life*. A measure of the productive life of an oil and gas property or a group of oil and gas properties, expressed in years. Reserve life for the years ended December 31, 2011, 2010 or 2009 equal the estimated net proved reserves attributable to a property or group of properties divided by production from the property or group of properties for the four fiscal quarters preceding the date as of which the proved reserves were estimated.

**Terms used to describe the legal ownership of the Company's oil and gas properties**

- *Royalty interest*. A real property interest entitling the owner to receive a specified portion of the gross proceeds of the sale of oil and natural gas production or, if the conveyance creating the interest provides, a specific portion of oil and natural gas produced, without any deduction for the costs to explore for, develop or produce the oil and natural gas. A royalty interest owner has no right to consent to or approve the operation and development of the property, while the owners of the working interests have the exclusive right to exploit the minerals on the land.
- *Working interest.* A real property interest entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas. A working interest owner who owns a portion of the working interest may participate either as operator or by voting his percentage interest to approve or disapprove the appointment of an operator and drilling and other major activities in connection with the development and operation of a property.

**Terms used to describe seismic operations**

- *Seismic data*. Oil and gas companies use seismic data as their principal source of information to locate oil and gas deposits, both to aid in exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computers are then used to process the raw data to develop an image of underground formations.

- *2-D seismic data*. 2-D seismic survey data has been the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data.
- *3-D seismic data*. 3-D seismic data is collected using a grid of energy sources, which are generally spread over several miles. A 3-D survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

# PART I

## Item 1. Business

### BACKGROUND

VAALCO Energy, Inc., a Delaware corporation incorporated in 1985, is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. VAALCO owns producing properties and conducts exploration activities as an operator in Gabon, West Africa, conducts exploration activities as an operator in Angola, West Africa, conducts exploration activities as an operator and has conducted exploration activities as a non-operator in the British North Sea. VAALCO is the operator of three shale properties in the United States located in Montana and Texas. The Company also owns minor interests in conventional production activities as a non-operator in the United States. As used in this report, the terms “Company”, “we, “us”, and “VAALCO” mean VAALCO Energy, Inc. and its subsidiaries, unless the context otherwise requires. The Company’s corporate headquarters are located at 4600 Post Oak Place, Suite 300, Houston, Texas 77027 where the telephone number is (713) 623-0801.

VAALCO’s international subsidiaries are VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Angola (Kwanza), Inc., VAALCO UK (North Sea), Ltd., and VAALCO International, Inc. VAALCO Energy (USA), Inc. holds interests in properties located in the United States.

### RECENT DEVELOPMENTS

#### Offshore Gabon

The Company’s primary source of revenue is from the Etame Production Sharing Contract related to the Etame Marin block located offshore the Republic of Gabon. VAALCO operates the Etame Marin block on behalf of a consortium of companies. At December 31, 2011, VAALCO owned a 30.35% interest in the exploration acreage within the Etame Marin block. The Company owns a 28.1% interest in the development areas in and surrounding the Etame, Avouma, South Tchibala and Ebouri fields, each of which is located on the Etame Marin block. The development areas were subject to a 7.5% back-in by the Government of Gabon, which occurred for these fields after their successful development.

The Company produces from the Etame, Avouma, South Tchibala and Ebouri fields on the block. Oil production commenced from the Etame field in September 2002, from the Avouma and South Tchibala fields in January 2007, and from the Ebouri field in January 2009. During 2011, the Etame, Avouma, South Tchibala and Ebouri fields produced approximately 8.1 million bbls (2.3 million bbls net to the Company). The Company’s share of barrels sold reflect a reduction for royalty and an allocation of cost oil and profit oil.

The Company has two platforms in the Etame Marin block. During 2011, the Company invested in platform modifications to both of the offshore platforms to accommodate the drilling of additional wells planned to begin in the second half of 2012. Additionally, the Company commenced electrical and power generation upgrades on both platforms. The Company also invested in the construction of water knock-out facilities for the Avouma platform, which it expects to install in mid-2012 along with a new personnel accommodation module.

During 2011, plans to build a third platform to be located in the Etame field were advanced resulting in the contracting for detailed engineering specifications in early 2012. This platform would allow the Company to drill multiple wells in the Etame field. A possible fourth platform continues to be evaluated by the Company and its block partners to develop the 2010 discovery in the Southeast Etame area as part of future development plans for the Etame Marin block.

The sixth exploration period expires in July 2014. Prior to the expiration of this period, the Company is obligated to drill two exploration wells. In 2010, the Company fulfilled one of the two required exploration well obligations with the drilling of the Omangou well, an unsuccessful effort. The remaining commitment in the exploration period is the drilling of one additional exploration well.

**Onshore Gabon**

The Company executed a farm-out agreement in August 2010 with Total Gabon on the Mutamba Iroru block located onshore near the coast in central Gabon. The Mutamba Iroru block contains an exploration area of approximately 270,000 acres. Under the terms of the agreement, the Company and Total Gabon committed to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. During 2011, the seismic work was substantially completed. Drilling of the exploration well is expected in mid-2012. In return for funding 75% of the work commitment (seismic reprocessing and exploration well costs), Total Gabon will receive a 50% interest on the permit. In 2010, the exploration permit was successfully extended until May 2012 and an application for a further extension is expected to be made in the first quarter of 2012. However, the Company can provide no assurances that such a request will be granted.

**Offshore Angola**

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Following the decree, the Company and the government of Angola have been working together to obtain a replacement partner. Options to amend the two-well commitment are also being discussed with the Angolan government. Because of the uncertainty surrounding the outcome of the discussions with the Angolan government, the Company recorded a full allowance of $4.4 million in 2011, against the accounts receivable from partners for the amounts owed to the Company above its 40% working interest plus the 10% carried interest. In early 2012, the Angolan government granted a further one year extension for drilling the two exploration commitment wells in accordance with the production sharing contract.

Due to the timing uncertainty of obtaining a replacement partner and the outcome of discussions regarding modifying the drilling well commitments required by the production sharing contract, a time extension may be necessary beyond the current expiration date of November 30, 2012. The Company can provide no assurances that such an extension will be granted, if necessary. If the government of Angola were to deny a request for a further time extension, the Company may be required to impair its leasehold costs and other investments totaling $11.0 million as of December 31, 2011. The Company may also have to make a $10.0 million payment for failing to drill the two exploration commitment wells.

**Onshore Domestic-Texas**

The Company acquired a 640 acre lease in the Granite Wash formation in North Texas in December 2010 and a 480 acre lease in the same formation in July 2011. The first well on the initial acreage began production in August 2011, although mechanical problems with the well exist and the Company recorded an impairment on the well in the fourth quarter of 2011. In November 2011, the Company commenced drilling a second well on the initial Granite Wash formation lease. The well landed in the objective reservoir in February 2012. Subject to successful fracking in March 2012, we expect production to begin soon thereafter.

The acreage on the first Granite Wash formation is held by production. The expiration date of the primary term of the second Granite Wash lease is August 2014.

**Onshore Domestic—Montana**

In May 2011, the Company acquired a 70% working interest in approximately 5,200 acres (3,640 net acres) in Sheridan County, Montana in the Middle Bakken formation. The Company plans to drill two wells on this acreage in 2012.

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. Pursuant to the terms of the acquisition, the Company is required to drill three wells at its sole cost, one of which must be drilled by June 1, 2012 and the remaining two wells must be drilled by the end of 2012. A vertical exploration well, which meets the time requirement for drilling the first well, was spudded in December 2011 to evaluate the formations. Two additional wells are expected to be drilled on this property in 2012 in accordance with the terms of the lease.

**Domestic—Outside Operated**

The Company has minor interests in Brazos County, Texas producing from the Buda/Georgetown formations. The Company also owns certain minor non-operated interests in the Ship Shoal area of the Gulf of Mexico and in Pickens County, Alabama. No significant activity was undertaken on these properties in 2011.

See Note 13 to the Company's consolidated financial statements for financial information about the Company's segments.

## AVAILABLE INFORMATION

The Company files annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). You may read and copy any document the Company files at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. The Company's SEC filings are also available to the public at the SEC's website at www.sec.gov.

You may also obtain copies of the Company's annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from the Company's website at www.vaalco.com. No information from the SEC's or the Company's website is incorporated by reference herein. The Company has placed on its website copies of its Audit Committee Charter, Code of Business Conduct and Ethics, and Code of Ethics for the Chief Executive Officer and Chief Financial Officer. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, VAALCO Energy, Inc., 4600 Post Oak Place, Suite 300, Houston, Texas 77027.

## STRATEGY

**International**

The Company's international strategy is to pursue selective opportunities that are characterized by reasonable entry costs, favorable economic terms, high reserve potential relative to capital expenditures and the availability of existing technical data that may be further developed. The Company believes that it has strong management and technical expertise with proven abilities in identifying international opportunities and establishing favorable operating relationships with host governments and local partners familiar with the local practices and infrastructure. The Company owns producing properties and conducts exploration activities as operator of two exploration licenses in Gabon, and one exploration license in Angola.

In addition, the Company's production strategy is to maximize the value of the reserves discovered in Gabon through exploitation of the Etame Marin block (comprised of the Etame, Avouma, South Tchibala and Ebouri fields) totaling approximately 759,000 gross acres.

**Domestic**

The Company's domestic strategy is to selectively acquire resource based properties, including liquids-rich shale properties. Beginning in December 2010, the Company has acquired two small leases in the Granite Wash formation in Texas and two larger properties located in the Middle Bakken formation in Montana. The Company also has minor interests in outside operated properties located in Brazos County, Texas, in Pickens County, Alabama, and offshore Louisiana in the Ship Shoal area. The Company's strategy for the outside operated properties is to continue to own the interests and receive its revenue share of the production.

## CUSTOMERS

Substantially all of the Company's oil and gas is sold at the well head at posted or indexed prices under short-term contracts, as is customary in the industry. In Gabon, the Company sold oil under a contract with Mercuria Trading NV ("Mercuria") which ran through calendar year 2011. For the 2012 calendar year, the Company will also sell its oil under a contract with Mercuria. While the loss of Mercuria as a buyer might have a material effect on the Company in the short term, management believes that the Company would be able to obtain other customers for its crude oil.

Domestic operated production in Texas is sold via two contracts, one for oil and one for gas/natural gas liquids. The Company has access to several alternative buyers for oil and gas sales domestically.

## EMPLOYEES

As of December 31, 2011, the Company had 94 full-time employees and consultant contractors, 50 of whom were located in Gabon and 8 of whom were located in Angola. The Company is not yet subject to any collective bargaining agreements, although most of the national employees in Gabon are members of the NEOP (National Organization of Petroleum Workers) union. The Company and NEOP began negotiating a collective bargaining agreement in the first quarter of 2011 which has not been completed as of the end of 2011. The Company believes its relations with its employees are satisfactory.

## COMPETITION

The oil and gas industry is highly competitive. Competition is particularly intense from other independent operators and from major oil and natural gas companies with respect to acquisitions of desirable oil and gas properties and contracting for drilling equipment**.** There is also competition for the hiring of experienced personnel. In addition, the drilling, producing, processing and marketing of oil and gas is affected by a number of factors beyond the control of the Company, including but not limited to shortages of drilling rigs, pipe and personnel, which may delay drilling, increase prices and have other adverse effects which cannot be accurately predicted.

The Company's competition for acquisitions, exploration, development and production includes the major oil and gas companies in addition to numerous independent oil companies, individual proprietors, investors and others. Many of these competitors possess financial, technical and personnel resources substantially in excess of those available to the Company, giving those competitors an enhanced ability to evaluate and acquire desirable leases properties or prospects. The ability of the Company to generate reserves in the future will depend on its ability to select and acquire suitable producing properties and prospects for future drilling and exploration.

**INSURANCE**

In accordance with industry practice, the Company maintains insurance against some, but not all, of the operating risks to which its business is exposed. The Company currently has insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to its oil and gas properties, operational control of offshore wells, aviation, auto liability, marine liability, worker's compensation and employer's liability, among other things. At the depths and in the areas in which the Company operates, and in light of the vertical and horizontal drilling that it undertakes, the Company typically does not encounter high pressures or extreme drilling conditions.

Currently, the Company has Operator's Extra Expense insurance coverage up to $100 million per occurrence, which includes damage to equipment and sudden and accidental environmental liability coverage. The Company's insurance policies contain maximum policy limits and in most cases, deductibles (generally ranging from $100,000 to $1 million) that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, the Company carries $75 million of general liability insurance to cover bodily injury, property damage and pollution affecting third parties arising from its operations.

The Company requires all of its third-party contractors to sign master service agreements in which they agree to indemnify the Company for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider. Similarly, the Company generally agrees to indemnify each third-party contractor against claims made by the Company's employees and other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations for the Company sign the master service agreements containing the indemnification provisions noted above. The Company does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, the Company believes its general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

The Company re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that the Company will be able to maintain insurance in the future at rates that we consider reasonable and it may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

**ENVIRONMENTAL REGULATIONS**

**General**

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control in the United States, Gabon and Great Britain and will be subject to the laws and regulations of Angola when exploration drilling begins. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing laws, rules and regulations regulating the release of materials in the environment or otherwise relating to the protection of the environment will not have a material effect upon the Company's capital expenditures, earnings or competitive position with respect to its existing assets and operations. The Company cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities. In part because they are developing countries, it is unclear how quickly and to what extent Gabon or Angola will increase their regulation of environmental issues in the future; any significant increase in the regulation or enforcement of environmental issues by Gabon or Angola could have a material effect on the Company. Developing countries, in certain instances, have patterned environmental laws after those in the United States which are discussed below. However, the extent to which any environmental laws are enforced in developing countries varies significantly.

In the United States, environmental laws and regulations may require the acquisition of permits before drilling commences, the installation of pollution control equipment for our operations, special handling or disposal of materials used in our operations, or remedial measures to mitigate pollution from our operations or on the properties on which we operate. These laws and regulations may also restrict the types of substances used in our drilling operations which can be used or released into the environment or limit or prohibit drilling activities on certain lands such as wetlands or sensitive protected areas.

As a general matter, the oil and gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. The trend has been the enactment of new or more stringent requirements on the oil and gas industry. These changes result in increased operating costs, and additional changes could results in further increases in our costs for environmental compliance.

**Environmental Regulations in the United States**

*Solid and Hazardous Waste*

The Company currently owns or leases, and in the past has owned or leased, properties that have been used for the exploration and production of oil and gas for many years. Although the Company has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other solid wastes may have been disposed or released on or under the properties owned or leased by the Company or on or under locations where such wastes have been taken for disposal. In addition, some of these properties are or have been operated by third parties. The Company has no control over such entities' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. State and federal laws applicable to oil and gas wastes and properties have gradually become stricter over time. The Company could, in the future, be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

The Company generates wastes, including hazardous wastes that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The Environmental Protection Agency ("EPA") and various state agencies have limited the disposal options for certain wastes, including wastes designated as hazardous under RCRA and state analogs ("Hazardous Wastes"). Furthermore, although oil and gas wastes generally are exempt from regulation as hazardous waste, certain wastes generated by the Company may be subject to RCRA or comparable state statutes. It is possible that certain wastes generated by the Company's oil and gas operations that are currently exempt may in the future be designated as Hazardous Wastes under RCRA or other applicable statutes and, therefore, may be subject to more rigorous and costly disposal requirements.

*Superfund*

The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, generally imposes joint and several liability for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances ("Hazardous Substances"). These classes of persons, or so-called potentially responsible parties ("PRPs"), include the current and certain past owners and operators of a facility where there has been a release or threat of release of a Hazardous Substance and persons who disposed of or arranged for the disposal of Hazardous Substances found at a facility. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the costs of such action.

Although CERCLA generally exempts "petroleum" from the definition of Hazardous Substance, in the course of its operations, the Company has generated and will generate substances that may fall within CERCLA's definition of Hazardous Substance and may have disposed of these substances at disposal sites owned and operated by others. The Company may also be the owner or operator of sites on which Hazardous Substances have been released. To its knowledge, neither the Company nor its predecessors have been designated as a PRP by the EPA under CERCLA; the Company also does not know of any prior owners or operators of its properties that are named as PRPs related to their ownership or operation of such properties. States such as Texas have comparable statutes which may cover substances (including petroleum) in addition to those covered under CERCLA**.** In the event contamination is discovered at a site on which the Company is or has been an owner or operator or to which the Company sent regulated substances, the Company could be liable for costs of investigation and remediation and natural resources damages.

*Clean Water Act*

The Clean Water Act ("CWA") and analogous state laws impose restrictions and strict controls regarding the discharge (including spills and leaks) of pollutants, including produced waters and other oil and natural gas wastes, into state waters and waters of the United States, a term broadly defined. These controls have become more stringent over the years, and it is probable that additional restrictions will be imposed in the future. Generally, permits must be obtained to discharge pollutants. The CWA provides for civil, criminal and administrative penalties for unauthorized discharges of oil and hazardous substances and of other pollutants. It imposes substantial potential liability for the costs of removal or remediation associated with discharges of oil or other pollutants. The CWA also prohibits the discharge of fill materials to regulated waters, including wetlands, without a permit. State laws governing discharges to water also provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other pollutants, into state waters. In addition, the EPA has promulgated regulations that may require the Company to obtain permits to discharge storm water runoff, including discharges associated with construction activities. In the event of an unauthorized discharge of wastes, the Company may be liable for penalties and cleanup and response costs.

*Oil Pollution Act*

The Oil Pollution Act of 1990 ("OPA"), which amends and augments oil spill provisions of the CWA, imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, the Company may be liable for costs and damages.

The OPA also imposes ongoing requirements on a responsible party, including proof of financial responsibility to cover at least some costs in a potential spill. Certain amendments to the OPA that were enacted in 1996 require owners and operators of offshore facilities that have a worst case oil spill potential of more than 1,000 bbls to demonstrate financial responsibility in amounts ranging from $10 million in specified state waters and $35 million in federal outer continental shelf ("OCS") waters, with higher amounts, up to $150 million based upon worst case oil-spill discharge volume calculations. In light of recent events, it is possible that these requirements may become more stringent. The Company believes that currently it has established adequate proof of financial responsibility for its offshore facilities.

*Safe Drinking Water Act and Hydraulic Fracturing*

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities (except where diesel is a component of the fracturing fluid). Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal and state levels that could result in regulation of hydraulic fracturing becoming more stringent and costly. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with interim results of the study anticipated to be available by late 2012 and final results anticipated in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming; this study remains subject to review and public comment.

In addition, a committee of the U.S. House of Representatives conducted an investigation of hydraulic fracturing practices. Moreover, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing by eliminating the current exemption in the Safe Drinking Water Act, and, further, to require disclosure of the chemicals used in the fracturing process. Also, some states have adopted, and other states are considering adopting, regulations that restrict hydraulic fracturing in certain circumstances or that require disclosure of the chemicals in the fracturing fluids. There are reports that the Bureau of Land Management is considering regulations on hydraulic fracturing activities on federal lands. It is not clear what form the regulations will take and what burdens may be imposed by these regulations.

Further, the EPA has announced an initiative under the Toxic Substances Control Act (“TSCA”) to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where the Company conducts business, the Company could incur substantial compliance costs and such requirements could adversely delay or restrict its ability to conduct fracturing activities on its assets.

*National Environmental Policy Act*

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. To the extent that our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA, this process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

*Endangered Species Act*

The Endangered Species Act (“ESA”) was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species’ critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If the Company were to have a portion of its leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

*Climate Change Legislation*

More stringent laws and regulations relating to climate change and greenhouse gases ("GHGs") may be adopted in the future and could cause us to incur material expenses in complying with them. The EPA has adopted rules under the Clean Air Act ("CAA") for the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, both houses of the United States Congress have considered legislation to reduce emissions of greenhouse gases without any ultimate resolution and many states have already taken legal measures to reduce GHG emissions, including, in a few locations, the consideration of a cap and trade program. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. Depending on the regulatory reach of the EPA's rules or new CAA legislation or implementing regulations restricting the emission of GHGs or state programs, the Company could incur significant costs to control its emissions and comply with regulatory requirements. In addition, in October 2009, the EPA adopted a mandatory GHG emissions reporting program which imposes reporting and monitoring requirements on various industries and in November 2010, expanded this GHG reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. The Company will incur costs to monitor, keep records of, and report emissions of GHGs. We do not believe that our compliance with applicable monitoring, recordkeeping and reporting requirements under the reporting rule as recently amended will have a material adverse effect on our results of operations or financial position.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how federal and state regulation of GHGs will unfold and how it may impact our industry. Moreover, the federal, regional, state and local regulatory initiatives could adversely affect the marketability of the oil and natural gas that the Company produces. The impact of such future programs cannot be predicted, but the Company does not expect its operations to be affected any differently than other similarly situated domestic competitors.

*Air Emissions*

The Company's operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. At the Federal level, the Clean Air Act is the primary statute governing air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants might require installation of additional controls. Administrative enforcement actions for failure to comply with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require the Company to forego construction, modification or operation of certain air emission sources.

On July 28, 2011, the EPA proposed a rule to subject oil and gas operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) programs under the Clean Air Act, and to impose new and amended requirements under both programs. Under the proposal, the EPA would, among other things, amend standards applicable to natural gas processing plants and would expand the NSPS to include all oil and gas operations, imposing requirements on those operations. The EPA is also proposing NSPS standards for completions of hydraulically fracturing gas wells. The proposed standards include the reduced emission completion techniques. The NESHAPS proposal includes maximum achievable control technology (MACT) standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. The EPA is under a court order to finalize the rules, with the current deadline of April 3, 2012. Should these rules become final and applicable to our operations, they could result in increased operating and compliance costs, increased regulatory burdens and delays in our operations.

*Coastal Coordination*

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act ("CZMA") was passed in 1972 to preserve and, where possible, restore the natural resources of the Nation's coastal zone. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development.

In Texas, the Legislature enacted the Coastal Coordination Act ("CCA"), which provides for the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. The act establishes the Texas Coastal Management Program ("CMP"). The CMP is limited to the nineteen counties that border the Gulf of Mexico and its tidal bays. The CCA provides for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the Coastal Management Plan. This review may impact agency permitting and review activities and add an additional layer of review to certain activities undertaken by the Company.

*OSHA and Other Regulations*

The Company is subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require the Company to organize and/or disclose information about hazardous materials used or produced in its operations.

*Hydraulic Fracturing*

All of the acreage and undeveloped reserves within the Granite Wash formation are subject to hydraulic fracturing. The hydraulic fracturing process is integral to our overall drilling and completion costs in the Granite Wash formation and represents approximately 40% of the total drilling/completion costs per well.

The Company diligently reviews best practices and industry standards, and complies with all regulatory requirements in the protection of these potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time, and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources.

Based on current drilling techniques, a typical fracturing procedure for a well in the Granite Wash formation uses approximately 5.0 million gallons of fluid, 4.9 million gallons of which is fresh water, and approximately 0.1 million gallons-equivalent of sand. By volume, fresh water makes up nearly 98% of the total fracturing fluid. Less than 1% of the remaining fluid is comprised of chemicals that are found in household or consumer products.

In compliance with the law enacted in Texas in June 2011 and regulations adopted in December 2011, the Company will disclose hydraulic fracturing data to the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission chemical registry. This disclosure is required for each chemical ingredient that is subject to the requirements of OSHA regulations, as well as the total volume of water used in the hydraulic fracturing treatment. A copy of the completed form will be submitted to the Railroad Commission of Texas with the completion report for the well. Additionally, a list of all other chemical ingredients not required by the registry will also be provided to the Railroad Commission for disclosure on a publicly accessible website.

There have not been any incidents, citations or suits related to the Company's hydraulic fracturing activities involving environmental concerns.

**FORWARD-LOOKING STATEMENTS**

This Report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, which are intended to be covered by the safe harbors created by those laws. The Company has based these forward-looking statements on its current expectations and projections about future events. These forward-looking statements include information about possible or assumed future results of the Company's operations. All statements, other than statements of historical facts, included in this Report that address activities, events or developments that the Company expects or anticipates may occur in the future, including without limitation, statements regarding the Company's financial position, operating performance and results, reserve quantities and net present values, market prices, business strategy, derivative activities, the amount and nature of capital expenditures, plans and objectives of the Company's management for future operations are forward-looking statements. When the Company uses words such as "anticipate," "believe," "estimate," "expect," "intend," "forecast," "outlook," "aim," "will," "could," "should," "may," "likely," "plan," "probably" or similar expressions, the Company is making forward-looking statements. Many risks and uncertainties that could affect the Company's future results and could cause results to differ materially from those expressed in the Company's forward-looking statements include, but are not limited to:

- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil to commercial markets;
- discovery, acquisition, development and replacement of oil and gas reserves;
- timing and amount of future production of oil and gas;
- hedging decisions, including whether or not to enter into derivative financial instruments;
- our ability to effectively integrate companies and properties that we acquire;
- general economic conditions, including any future economic downturn, disruption in financial markets and the availability of credit;
- changes in customer demand and producers' supply;
- future capital requirements and the Company's ability to attract capital;
- currency exchange rates;
- actions by the governments and events occurring in the countries in which we operate;
- actions by our venture partners;
- compliance with, or the effect of changes in, governmental regulations regarding the Company's exploration and production, including those related to climate change;
- actions of operators of the Company's oil and gas properties; and
- weather conditions.

The information contained in this Report, including the information set forth under the heading "Risk Factors," identifies additional factors that could cause the Company's results or performance to differ materially from those the Company expresses in its forward-looking statements. Although the Company believes that the assumptions underlying its forward-looking statements are reasonable, any of these assumptions and therefore also the forward-looking statements based on these assumptions, could themselves prove to be inaccurate. In light of the significant uncertainties inherent in the forward-looking statements which are included in this Report, the Company's inclusion of this information is not a representation by the Company or any other person that the Company's objectives and plans will be achieved. When you consider the Company's forward-looking statements, you should keep in mind these risk factors and the other cautionary statements in this Report.

The Company's forward-looking statements speak only as of the date made and the Company will not update these forward-looking statements unless the securities laws require the Company to do so. The Company's forward-looking statements are expressly qualified in their entirety by this cautionary statement. In light of these risks, uncertainties and assumptions, any forward-looking events discussed in this Report may not occur.

**Item 1A. Risk Factors**

You should carefully consider the following risk factors in addition to the other information included in this Report. If any of these risks or uncertainties actually occurs, our business, financial condition and results of operations could be materially adversely affected. Additional risks not presently known to us or which we consider immaterial based on information currently available to us may also materially adversely affect us. In this section, the terms "VAALCO", "we", "us" and "our" refer to VAALCO Energy, Inc. and its subsidiaries, unless the context clearly indicates otherwise.

*Almost all of the value of our production and reserves is concentrated in a single block offshore Gabon, and any production problems or reductions in reserve estimates related to this property would adversely impact our business.*

The Etame field consisting of five producing wells, the Avouma and South Tchibala fields consisting of one well and two wells, respectively, and the Ebouri field with three producing wells constituted almost 98% of our total production for the year ended December 31, 2011. In addition, at December 31, 2011, 94% of our total net proved reserves were attributable to these fields. If mechanical problems, storms or other events curtailed a substantial portion of this production, or if the actual reserves associated with this producing property are less than our estimated reserves, our results of operations and financial condition could be materially adversely affected.

*Our results of operations and financial condition could be adversely affected by changes in currency exchange rates.*

Our results of operations and financial condition are affected by currency exchange rates. While oil sales are denominated in U.S. dollars, portions of our operating costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing operating costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in response to international political conditions, general economic conditions, the European sovereign debt crisis and other factors beyond our control.

*A decrease in oil and gas prices may adversely affect our results of operations and financial condition.*

Our revenues, cash flow, profitability and future rate of growth are substantially dependent upon prevailing prices for oil and gas. Our ability to borrow funds and to obtain additional capital on attractive terms is also substantially dependent on oil and gas prices. Historically, world-wide oil and gas prices and markets have been volatile, and may continue to be volatile in the future. The average price for crude we sold in 2011 was $111.93 per barrel compared to $78.38 per barrel in 2010, and $59.54 per barrel in 2009.

Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include international political conditions, including recent uprisings and political unrest in the Middle East and Africa, the European sovereign debt crisis, the domestic and foreign supply of oil and gas, the level of consumer demand, weather conditions, domestic and foreign governmental regulations, the price and availability of alternative fuels, the health of international economic and credit markets, and general economic conditions. In addition, various factors, including the effect of federal, state and foreign regulation of production and transportation, general economic conditions, changes in supply due to drilling by other producers and changes in demand may adversely affect our ability to market our oil and gas production. Any significant decline in the price of oil or gas would adversely affect our revenues, operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of our oil and gas properties and our planned level of capital expenditures.

*If there is a sustained economic downturn or recession in the United States or globally, oil and gas prices may fall and may become and remain depressed for a long period of time, which may adversely affect our results of operations.*

In recent years, we experienced an economic downturn or a recession in the United States and globally. The reduced economic activity associated with the economic downturn or recession may reduce the demand for, and the prices we receive for, our oil and gas production. A sustained reduction in the prices we receive for our oil and gas production will have a material adverse effect on our results of operations.

*Unless we are able to replace reserves which we have produced, our cash flows and production will decrease over time.*

Our future success depends upon our ability to find, develop or acquire additional oil and gas reserves that are economically recoverable. Except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, our estimated net proved reserves will generally decline as reserves are produced. There can be no assurance that our planned development and exploration projects and acquisition activities will result in significant additional reserves or that we will have continuing success drilling productive wells at economic finding costs. The drilling of oil and gas wells involves a high degree of risk, especially the risk of dry holes or of wells that are not sufficiently productive to provide an economic return on the capital expended to drill the wells. In addition, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including title problems, weather conditions, political instability, availability of capital, economic/currency imbalances, compliance with governmental requirements, receipt of additional seismic data or the reprocessing of existing data, material changes in oil or gas prices, prolonged periods of historically low oil and gas prices, failure of wells drilled in similar formations or delays in the delivery of equipment and availability of drilling rigs. With the exception of our property acquired in the Granite Wash formation in North Texas in late 2010 and early 2011, and our properties acquired in the Middle Bakken and deeper formations in Montana in 2011, our current domestic oil and gas producing properties are operated by third parties and, as a result, we have limited control over the nature and timing of exploration and development of such properties or the manner in which operations are conducted on such properties.

*Substantial capital, which may not be available to us in the future, is required to replace and grow reserves.*

We make, and will continue to make, substantial capital expenditures for the acquisition, exploitation, development, exploration and production of oil and gas reserves. Historically, we have financed these expenditures primarily with cash flow from operations, debt, asset sales, and private sales of equity. During 2011, we participated, and in 2012 we expect to continue to participate, in the further exploration and development projects on our international properties. In Gabon and Angola, we are the operator of the blocks and are thus responsible for contracting on behalf of all the remaining parties participating in the project. We rely on the timely payment of cash calls by our partners to pay for the 69.65% share of the Etame budget. Assuming a replacement partner is obtained and at the same working interest as the former partner, we will rely on the timely payment of cash calls by such partner to pay for the 50% share of the Angola Block 5 budget.

We also expect to continue exploration and development on our Bakken acreage and Granite Wash properties in the U.S. However, if lower oil and gas prices, operating difficulties or declines in reserves result in our revenues being less than expected or limit our ability to borrow funds, or our partners fail to pay their share of project costs, we may have a limited ability, particularly in the current economic environment, to expend the capital necessary to undertake or complete future drilling programs. We cannot assure you that additional debt or equity financing or cash generated by operations will be available to meet these requirements.

*Our drilling activities require us to risk significant amounts of capital that may not be recovered.*

Drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. There can be no assurance that new wells drilled by us will be productive or that we will recover all or any portion of our investment. Drilling for oil and gas may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating wells is often uncertain and cost overruns are common. Our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, many of which are beyond our control, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery of equipment and services.

As part of our exploration and development operations, we have expanded, and expect to further expand, the application of horizontal drilling and multi-stage hydraulic fracture stimulation techniques. The utilization of these techniques requires substantially greater capital expenditures as compared to the drilling of a vertical well. The incremental capital expenditures are the result of additional hydraulic fracture stages in horizontal wellbores.

*Weather, unexpected subsurface conditions and other unforeseen operating hazards may adversely impact our oil and gas activities.*

The oil and gas business involves a variety of operating risks, including fire, explosions, blow-outs, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as oil spills, gas leaks, ruptures and discharges of toxic gases, the occurrence of any of which could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our production facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, collision and damage from severe weather conditions. The relatively deep offshore drilling conducted by us overseas involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable. The impact that any of these risks may have upon us is increased due to the low number of producing properties we own.

We maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant unfavorable event not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict whether insurance will continue to be available at a reasonable cost or at all.

*Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present values of our reserves.*

There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, including many factors beyond our control. Reserve engineering is a subjective process of estimating the underground accumulations of oil and gas that cannot be measured in an exact manner. The estimates included in this document are based on various assumptions required by the SEC, including unescalated prices and costs and capital expenditures subsequent to December 31, 2011, and, therefore, are inherently imprecise indications of future net revenues. Actual future production, revenues, taxes, operating expenses, development expenditures and quantities of recoverable oil and gas reserves may vary substantially from those assumed in the estimates. Any significant variance in these assumptions could materially affect the estimated quantity and value of reserves incorporated by reference in this document. In addition, our reserves may be subject to downward or upward revision based upon production history, results of future development, availability of funds to acquire additional reserves, prevailing oil and gas prices and other factors. Moreover, the calculation of the estimated present value of the future net revenue using a 10% discount rate as required by the SEC is not necessarily the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our reserves or the oil and gas industry in general. It is also possible that reserve engineers may make different estimates of reserves and future net revenues based on the same available data.

The estimated future net revenues attributable to our net proved reserves are prepared in accordance with current SEC guidelines, and are not intended to reflect the fair market value of our reserves. In accordance with the rules of the SEC, our reserve estimates are prepared using an average of beginning of month prices received for oil and gas for the preceding twelve months. Future reductions in prices below the average calculated for 2011 would result in the estimated quantities and present values of our reserves being reduced.

A substantial portion of our proved reserves are or will be subject to service contracts, production sharing contracts and other arrangements. The quantity of oil and gas that we will ultimately receive under these arrangements will differ based on numerous factors, including the price of oil and gas, production rates, production costs, cost recovery provisions and local tax and royalty regimes. Changes in many of these factors do not affect estimates of U.S. reserves in the same way they affect estimates of proved reserves in foreign jurisdictions, or will have a different effect on reserves in foreign countries than in the United States. As a result, proved reserves in foreign jurisdictions may not be comparable to proved reserve estimates in the United States.

*We have less control over our foreign investments than domestic investments, and turmoil in foreign countries may affect our foreign investments.*

Our international assets and operations are subject to various political, economic and other uncertainties, including, among other things, the risks of war, expropriation, nationalization, renegotiation or nullification of existing contracts, taxation policies, foreign exchange restrictions, changing political conditions, international monetary fluctuations, currency controls and foreign governmental regulations that favor or require the awarding of drilling contracts to local contractors or require foreign contractors to employ citizens of, or purchase supplies from, a particular jurisdiction. In addition, if a dispute arises with foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons, especially foreign oil ministries and national oil companies, to the jurisdiction of the United States.

Private ownership of oil and gas reserves under oil and gas leases in the United States differs distinctly from our ownership of foreign oil and gas properties. In the foreign countries in which we do business, the state generally retains ownership of the minerals and consequently retains control of, and in many cases participates in, the exploration and production of hydrocarbon reserves. Accordingly, operations outside the United States may be materially affected by host governments through royalty payments, export taxes and regulations, surcharges, value added taxes, production bonuses and other charges.

Almost all of our proven reserves are located offshore of the Republic of Gabon. As of December 31, 2011, we carried a gross investment of approximately $187.2 million including leasehold and asset retirement obligations on our balance sheet associated with the Etame, Avouma, South Tchibala and Ebouri fields in Gabon. We have operated in Gabon since 1995 and believe we have good relations with the current Gabonese government. However, there can be no assurance that present or future administrations or governmental regulations in Gabon will not materially adversely affect our operations or cash flows.

*A third time extension for the drilling of two exploration wells in Angola may be necessary to prevent the loss of our investment in that country.*

Due to financial non-performance of the venture partner assigned by the government of Angola, our plans to drill the two obligatory wells have been delayed. A government decree effective December 1, 2010 removed the former partner from the production sharing agreement and provided us with a one year extension through the end of November 2011, which has subsequently been extended through the end of November 2012. We continue to work with the government of Angola to secure a replacement partner. After a new partner is obtained, another time extension may be required if reasonable time to drill the two commitment wells does not exist. We can give no assurances that another time extension, if necessary, will be granted. If the government of Angola were to deny a further time extension, the Company may be required to impair its leasehold costs and other investments with a carrying value of $11.0 million as of December 31, 2011. The Company may also have to make a $10.0 million payment for failing to drill the two exploration commitment wells.

*Competitive industry conditions may negatively affect our ability to conduct operations.*

We operate in the highly competitive areas of oil exploration, development and production. We compete with, and may be outbid by, competitors in our attempts to acquire exploration and production rights in oil and gas properties. These properties include exploration prospects as well as properties with proved reserves. There is also competition for contracting for drilling equipment and the hiring of experienced personnel. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain and hire the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to hire experienced personnel, especially for our accounting, financial reporting, tax and land departments;
- the location of, and our ability to access, platforms, pipelines and other facilities used to produce and transport oil and gas production; and
- the standards we establish for the minimum projected return on an investment of our capital.

Our competitors include major integrated oil companies and substantial independent energy companies, many of which possess greater financial, technological, personnel and other resources than we do. These companies may be able to pay more for oil and natural gas properties, evaluate, bid for and purchase a greater number of properties than our financial or human resources permit, and be better able than we are to continue drilling during periods of low oil and gas prices, to contract for drilling equipment and to secure trained personnel. Our competitors may also use superior technology which we may be unable to afford or which would require costly investment by us in order to compete.

*The distressed financial conditions of customers could have an adverse impact on us in the event these customers are unable to pay us for the products or services we provide.*

Some of our customers may experience, in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our financially distressed customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

*We may be unable to integrate successfully the operations of any acquisitions with our operations and we may not realize all the anticipated benefits of the recent acquisitions or any future acquisition.*

Failure to successfully assimilate any acquisitions could adversely affect our financial condition and results of operations.

Acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired business;
- the diversion of management's attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

*Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could result in material liabilities and adversely affect our financial condition.*

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and gas reserves. Any future acquisition will require an assessment of recoverable reserves, title, future oil and gas prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher valued properties and are inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. 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 potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact our financial condition.

Additional potential risks related to acquisitions include, among other things:

- incorrect assumptions regarding the future prices of oil and gas or the future operating or development costs of properties acquired;
- incorrect estimates of the oil and gas reserves attributable to a property we acquire;
- an inability to integrate successfully the businesses we acquire;
- the assumption of liabilities;

- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns; and
- losses of key employees at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

*Compliance with environmental and other government regulations could be costly and could negatively impact production.*

The laws and regulations of the United States, Gabon, Angola and Great Britain regulate our current business. Our operations could result in liability for personal injuries, property damage, natural resource damages, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties and the issuance of orders enjoining operations. In addition, we could be liable for environmental damages caused by, among others, previous property owners or operators. We could also be affected by more stringent laws and regulations adopted in the future, including any related to climate change and greenhouse gases and use of fracking fluids, resulting in increased operating costs. As a result, substantial liabilities to third parties or governmental entities may be incurred, the payment of which could have a material adverse effect on our financial condition, results of operations and liquidity. Additionally, more stringent GHG regulation could impact demand for oil and gas.

These laws and governmental regulations, which cover matters including drilling operations, taxation and environmental protection, may be changed from time to time in response to economic or political conditions and could have a significant impact on our operating costs, as well as the oil and gas industry in general. While we believe that we are currently in compliance with environmental laws and regulations applicable to our operations, no assurances can be given that we will be able to continue to comply with such environmental laws and regulations without incurring substantial costs.

*Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.*

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. Should climate change or other drought conditions occur, our ability to obtain water in sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

*Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation.*

The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

*If our assumptions underlying accruals for abandonment costs are too low, we could be required to expend greater amounts than expected.*

Almost all of our producing properties are located offshore. The costs to abandon offshore wells may be substantial. For financial accounting purposes, we record the fair value of a liability for an asset retirement obligation in the period in which it is incurred by capitalizing it as part of the carrying amount of the long-lived assets. No assurances can be given that such reserves will be sufficient to cover such costs in the future as they are incurred.

*From time to time we may hedge a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.*

We may reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. Hedging also prevents us from receiving the full advantage of increases in oil or gas prices above the maximum fixed amount specified in the hedge agreement. Conversely, hedging may limit our ability to realize cash flows from commodity price increases. In a typical hedge transaction, we have the right to receive from the hedge counterparty the excess of the maximum fixed price specified in the hedge agreement over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the maximum fixed price, we must pay the counterparty this difference multiplied by the quantity hedged even if we had insufficient production to cover the quantities specified in the hedge agreement. Accordingly, if we have less production than we have hedged when the floating price exceeds the fixed price, we must make payments against which there are no offsetting sales of production. If these payments become too large, the remainder of our business may be adversely affected.

In addition, hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations. This risk of counterparty performance is of particular concern given the disruptions that occurred in the financial markets that lead to sudden changes in a counterparty’s liquidity and hence their ability to perform under the hedging contract.

*The adoption of derivatives legislation by the U.S. Congress could have an adverse effect on the Company’s ability to use derivative instruments to reduce the effect of commodity price, interest rate, and other risks associated with its business.*

The Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), signed into law in 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation required the Commodities Futures Trading Commission (CFTC) and the Securities and Exchange Commission (SEC) to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. In July 2011, the CFTC granted temporary exemptive relief from certain swap regulation provisions of the legislation until December 21, 2011, or until the agency finalized the corresponding rules. In December 2011, the CFTC extended the potential latest expiration date of the exemptive relief to July 16, 2012. In its rulemaking under the new legislation, the CFTC has issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain *bona fide* hedging transactions or positions are exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize other regulations, including critical rulemaking on the definition of “swap”, “swap dealer” and “major swap participant.” Depending on our classification, the financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities. The financial reform legislation may also require the counterparties to derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts and reduce the availability of derivatives to protect against risks we encounter. 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 instruments 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 consolidated financial position, results of operations, or cash flows.

*Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.*

In recent years, the Obama administration's budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect the Company's financial condition and results of operations.

*We rely on our senior management team and the loss of a single member could adversely affect our operations.*

We are highly dependent upon our executive officers and key employees. The unexpected loss of the services of any of these individuals could have a detrimental effect on us. We do not maintain key man life insurance on any of our employees.

*We rely on a single purchaser of our Gabon production, which could have a material adverse effect on our results of operations.*

Effective January 2011, we sell all of our crude oil production in Gabon to Mercuria and the contract with Mercuria has been extended for calendar year 2012. The loss of Mercuria as a purchaser of our Gabon production could force the shut in of our Gabon production until the purchaser is replaced, and could have a material adverse effect on our results of operations.

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

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level (except for fracturing activity involving the use of diesel). The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and final results anticipated in 2014. In addition, in December 2011, the EPA published an unrelated draft report concluding that hydraulic fracturing caused groundwater pollution in a natural gas field in Wyoming; this study remains subject to review and public comment. A committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. Any other new laws or regulations that significantly restrict hydraulic fracturing could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. Further, the EPA has announced an initiative under TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

*There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected.*

Our management, including our Chief Executive Officer and Chief Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

## Item 1B. Unresolved Staff Comments

None.

## Item 2. Properties

*Offshore Gabon- Etame Marin block*

VAALCO has an interest in an approximately 759,000 gross acre offshore block in Gabon, the Etame Marin block, where it signed a production sharing contract in 1995. The block contains the Etame, Avouma, South Tchibala and Ebouri fields, all of which are in production, the Southeast Etame area where development plans are being made for this 2010 discovery, and the North Tchibala discovery for which there are no development plans at this time. These fields and discoveries consist of subsalt reservoirs that lie 20 miles offshore in approximately 250 feet of water depth.

VAALCO operates the Etame Marin block on behalf of a consortium of companies. At December 31, 2011, VAALCO owned a 30.35% interest in the exploration acreage within the Etame Marin block. The Company owns a 28.1% interest in the development areas in and surrounding the Etame, Avouma, South Tchibala and Ebouri fields. The development areas were subject to a 7.5% back-in by the Government of Gabon, which occurred for these fields after their successful development.

The Etame Marin block consortium approved the development of the Etame field in 2001. An application for commerciality was filed with the government of Gabon, and in November 2001 the consortium was awarded an approximately 12,000 gross acre exploitation area surrounding the field. The exploitation area has a term of 20 years (through 2021).

The Etame field has been developed at an aggregate cost of approximately $194.9 million ($52.9 million net to the Company). The development included drilling and completing subsea wells connected to a contracted floating production, storage and offloading vessel (“FPSO”). A successful development well was drilled in 2010 in this field. There are currently five wells producing in the Etame field.

During 2011, plans to build a third platform to be located in the Etame field were advanced resulting in the contracting for detailed engineering specifications in early 2012. This platform would allow the Company to drill multiple wells in the Etame field. A possible fourth platform continues to be evaluated by the Company and its block partners to develop the 2010 discovery in the Southeast Etame area as part of future development plans for the Etame Marin block.

In April 2005, a development plan for the joint development of the Avouma and South Tchibala fields was approved by the Gabon government. The Company was awarded an approximately 13,000 gross acre exploitation area which has a term of 20 years (until 2025). In 2006, the Company installed a platform in approximately 250 feet of water and drilled two development wells from the platform, one into each field. In 2010, a second development well in the South Tchibala field was drilled and successfully completed. The three development wells are tied back to the FPSO via a ten mile pipeline. Through December 31, 2011, the cost of developing the Avouma and South Tchibala fields was approximately $146.1 million ($43.2 million net to the Company).

The Company drilled the Ebouri discovery well to total depth in January 2004. In October 2006, the Gabon government approved the development plan for the Ebouri field and the Company was awarded an approximately 3,700 gross acre exploitation area which has a term of 20 years (until 2026). A platform was installed in July 2008, approximately seven miles from the FPSO and is tied back to the FPSO via a pipeline as was done for the Avouma and South Tchibala fields. The cost of developing the Ebouri field as of December 31, 2011 totaled approximately $188.1 million ($59.0 million net to the Company). The first development well began production in January 2009 and the second development well began producing crude oil in April 2009. A third development well began production in May 2010.

The Company has sold a total of 63.9 million gross bbls (15.2 million net bbls) from the fields within the Etame Marin block since startup in 2002 through December 31, 2011. During 2011, the Etame, Avouma, South Tchibala and Ebouri fields sold approximately 7.8 million gross bbls (1.9 million net bbls).

The Company negotiated an extension of the exploration permit on this block to 2014. The terms of the extension include an additional exploration well, bringing the total required under the permit to two exploration wells, and to acquire additional 3-D seismic data, which was acquired in 2011. One of the two commitment exploration wells has been met with the drilling of the Omangou prospect, an unsuccessful effort, in 2010.

*Onshore Gabon—Mutamba Iroru block*

In November 2005, the Company signed a production sharing contract for the Mutamba Iroru block onshore Gabon. The five year contract awarded the Company exploration rights to approximately 270,000 acres along the central coast of Gabon. The Mutamba Iroru block was previously held by Shell Gabon. The Company acquired aeromagnetic gravity data in 2008, and together with seismic data acquired from previous operators over the block in 2006 and 2007, drilled two exploration wells in 2009. Both wells encountered water bearing sands and were abandoned.

In 2010, in conjunction with executing a farm-out agreement with Total Gabon, the exploration period was extended until May 2012. This extension requires the Company to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. In return for funding 75% of the work commitment (seismic reprocessing and exploration well costs), Total Gabon will receive a 50% interest on the permit. The seismic reprocessing began in the first quarter of 2011 and was substantially completed by the end of 2011. The exploration well is expected to be drilled in mid-2012. An application for a further exploration period extension is expected to be made in the first quarter of 2012. However, the Company can provide no assurances that such a request will be granted.

*Offshore Angola—Block 5*

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million gross acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Following the decree, the Company and the government of Angola have been working together to obtain a replacement partner. Options to amend the two-well commitment are also being discussed with the Angolan government. Because of the uncertainty surrounding the outcome of the discussions with the Angolan government, the Company recorded a full allowance of $4.4 million in 2011 against the accounts receivable from partners for the amounts owed to the Company above its 40% working interest plus the 10% carried interest. In early 2012, the Angolan government granted a further one year extension for drilling the two exploration commitment wells in accordance with the production sharing contract.

Due to the timing uncertainty of obtaining a replacement partner and the outcome of discussions regarding modifying the drilling well commitments required by the production sharing contract, a time extension may be necessary beyond the current expiration date of November 30, 2012. The Company can provide no assurances that such an extension will be granted, if necessary. If the government of Angola were to deny a request for a further time extension, the Company may be required to impair its leasehold costs and other investments totaling $11.0 million as of December 31, 2011. The Company may also have to make a $10.0 million payment for failing to drill the two exploration commitment wells.

*Onshore Domestic—Texas*

The Company acquired a 640 acre lease in the Granite Wash formation in North Texas in December 2010 and a 480 acre lease in the same formation in July 2011. The first well on the initial acreage began production in August 2011, although mechanical problems with the well exist and the Company recorded an impairment on the well in the fourth quarter of 2011. The Company produced 3,656 bbls of oil and 255 MMcf of gas net to the Company from this well in 2011. In November 2011, the Company commenced drilling a second well. The well landed in the objective reservoir in February 2012. Subject to successful fracking in March 2012, we expect production to begin soon thereafter. Total capital expenditures for the well are expected to be $14.0 million, of which $4.0 million was incurred in 2011.

*Onshore Domestic—Montana*

In May 2011, the Company acquired a 70% working interest in approximately 5,200 gross acres (3,640 net acres) in Sheridan County, Montana in the Middle Bakken formation. The Company plans to drill two wells on this acreage in 2012.

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. A vertical exploration well was spudded in December 2011 to evaluate the formations. An additional two wells are expected to be drilled on this property in 2012.

*Domestic—Outside Operated*

The Company has minor interests in Brazos County, Texas producing from the Buda/Georgetown formations. The Company also owns certain minor non-operated interests in the Ship Shoal area of the Gulf of Mexico and in Pickens County, Alabama. During 2011, these wells produced approximately 330 bbls of oil and 29 million cubic feet of gas net to the Company. No significant activity was undertaken on these properties in 2011 and no capital expenditures are anticipated in 2012 for these properties.

*Aggregate Production*

Aggregate production data (net to the Company) for all of the Company's operations for the years 2011, 2010, and 2009 are shown below.

**Company Owned Production**

| | Year Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2011 | | | 2010 | | | 2009 | | |
| | BOE | Bbl | Mcf | BOE | Bbl | Mcf | BOE | Bbl | Mcf |
| Average daily production | | | | | | | | | |
| (Oil in BOPD, gas in MCFD) | | | | | | | | | |
| Etame, Gabon | 2,198 | 2,198 | — | 1,755 | 1,755 | — | 2,079 | 2,079 | — |
| Avouma/S.Tchibala, Gabon | 1,368 | 1,368 | — | 1,481 | 1,481 | — | 1,948 | 1,948 | — |
| Ebouri, Gabon | 1,542 | 1,542 | — | 1,460 | 1,460 | — | 1,275 | 1,275 | — |
| Hefley, USA(1) | 113 | 10 | 619 | — | — | — | — | — | — |
| Other USA properties | 14 | 1 | 80 | 9 | 2 | 38 | 5 | 2 | 16 |
| Total daily production | 5,235 | 5,119 | 699 | 4,705 | 4,698 | 38 | 5,307 | 5,304 | 16 |
| Average Sales Price ($/unit) | 110.12 | 111.92 | 5.23 | 78.31 | 78.39 | 4.79 | 59.52 | 59.54 | 4.79 |
| Production Cost ($/unit)(2) | 13.99 | 13.99 | 2.33 | 12.88 | 12.88 | 2.15 | 11.35 | 11.35 | 1.89 |

(1) The Hefley field is the first of the two Granite Wash formation leases acquired by the Company in North Texas

(2) Production cost in $/unit is the ratio of the company's production cost over units of production

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**RESERVE INFORMATION**

The table below sets forth the Company's estimated net proved reserves for the years ended December 31, 2011, 2010 and 2009 as prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. There have been no estimates of total proved net oil or gas reserves filed with or included in reports to any federal authority or agency other than the SEC since the beginning of the last fiscal year. The reserves are located in Gabon (offshore) and in Texas and Louisiana (onshore and offshore). Reserves estimated by our independent engineers at December 31, 2011, 2010, and 2009 reflect oil and natural gas spot prices based on the average prices during the 12-month period before the ending date of the period covered by this report determined as an unweighted, arithmetic average of the first-day-of-the-month price for each month within such period.

| | As of December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Crude Oil** | | | |
| Proved Developed Reserves (MBbls) | | | |
| United States | 19 | 4 | 4 |
| International | 3,835 | 5,025 | 4,791 |
| Total Proved Developed Reserves (MBbls) | 3,854 | 5,029 | 4,795 |
| Proved Undeveloped Reserves (MBbls) | | | |
| United States | 17 | — | — |
| International | 2,177 | 1,894 | 2,568 |
| Total Proved Undeveloped Reserves (MBbls) | 2,194 | 1,894 | 2,568 |
| Total Proved Reserves (MBbls) | | | |
| United States | 36 | 4 | 4 |
| International | 6,012 | 6,918 | 7,359 |
| Total Proved Reserves (MBbls) | 6,048 | 6,922 | 7,363 |
| **Natural Gas** | | | |
| Proved Developed Reserves (MMcf) | | | |
| United States | 856 | 23 | 23 |
| International | — | — | — |
| Total Proved Developed Reserves (MMcf) | 856 | 23 | 23 |
| Proved Undeveloped Reserves (MMcf) | | | |
| United States | 1,069 | — | — |
| International | — | — | — |
| Total Proved Undeveloped Reserves (MMcf) | 1,069 | — | — |
| Total Proved Reserves (MMcf) | | | |
| United States | 1,925 | 23 | 23 |
| International | — | — | — |
| Total Proved Reserves (MMcf) | 1,925 | 23 | 23 |
| Standardized measure of proved reserves (in thousands) | $ 166,187 | $ 124,824 | $ 102,518 |

**Proved Undeveloped Reserves**

The Company annually reviews all proved undeveloped reserves ("PUDs") to ensure an appropriate plan for development exists. Generally, the Company's PUDs are converted to proved developed reserves within five years of the date they are first booked as PUDs. The Company had 2,194 MBbls and 1,069 MMcf of PUDs at December 31, 2011, compared with 1,894 MBbls of PUDs at December 31, 2010. The Company did not convert any PUD's to proved developed reserves in 2011.

**Controls Over Reserve Estimates**

The Company's policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and GAAP. Compliance in reserves bookings is the responsibility of the Company's Vice President-Production, who is the Company's principal engineer. The Company's principal engineer has over 20 years of experience in the oil and gas industry, including over 10 years as a reserve evaluator, trainer or manager and is a qualified reserves estimator (QRE), as defined by the Society of Petroleum Engineers' standards. Further professional qualifications include a degree in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, the principal engineer is an active participant in industry reserve seminars, professional industry groups and has been a member of the Society of Petroleum Engineers for over 20 years.

The Company's controls over reserve estimates included retaining Netherland, Sewell & Associates, Inc. ("NSAI") as our independent petroleum and geological firm. The Company provided information about the Company's oil and gas properties, including production profiles, prices and costs, to NSAI and they prepare their own estimates of the reserves attributable to our properties. All of the information regarding reserves in this annual report is derived from the report of NSAI. The report of NSAI is included as an exhibit to this Report.

The reserves estimates shown herein have been independently evaluated by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Derek Newton and Mr. Pat Higgs. Mr. Newton has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Newton is a Licensed Professional Engineer in the State of Texas (No. 97689) and has over 26 years of practical experience in petroleum engineering, with over 14 years experience in the estimation and evaluation of reserves. He graduated from University College, Cardiff, Wales, in 1983 with a Bachelor of Science Degree in Mechanical Engineering and from Strathclyde University, Scotland, in 1986 with a Master of Science Degree in Petroleum Engineering. Mr. Higgs has been practicing consulting petroleum geology at NSAI since 1996. Mr. Higgs is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 985) and has over 35 years of practical experience in petroleum geosciences, with over 15 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1976 with a Bachelor of Science Degree in Geophysics. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The Audit Committee of the Board of Directors meets with management, including access to the Company's principal engineer, to discuss matters and policies related to reserves.

The following tables set forth the net proved reserves of the Company as of December 31, 2011, 2010 and 2009, and the changes during such periods.

| | Oil (MBbls) | Gas (MMCF) |
|---|---|---|
| PROVED RESERVES: | | |
| BALANCE AT JANUARY 1, 2009 | 7,422 | 30 |
| Production | (1,936) | (6) |
| Revisions of previous estimates | 783 | (1) |
| Extensions and discoveries | 1,094 | — |
| BALANCE AT DECEMBER 31, 2009 | 7,363 | 23 |
| Production | (1,715) | (38) |
| Revisions of previous estimates | 1,274 | 38 |
| Extensions and discoveries | — | — |
| BALANCE AT DECEMBER 31, 2010 | 6,922 | 23 |
| Production | (1,868) | (255) |
| Revisions of previous estimates | 959 | 31 |
| Extensions and discoveries | 35 | 2,126 |
| BALANCE AT DECEMBER 31, 2011 | 6,048 | 1,925 |

| | Oil (MBbls) | Gas (MMCF) |
|---|---|---|
| PROVED DEVELOPED RESERVES | | |
| Balance at January 1, 2009 | 4,751 | 30 |
| Balance at December 31, 2009 | 4,795 | 23 |
| Balance at December 31, 2010 | 5,029 | 23 |
| Balance at December 31, 2011 | 3,854 | 856 |

The Company does not book proved reserves on discoveries until such time as a development plan has been prepared and approved by the Company's partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the Company. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to the Company's properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place remain the property of the Gabon government.

In accordance with the current guidelines of the SEC, the Company's estimates of future net cash flow from the Company's properties and the present value thereof are made using oil and gas contract prices using a twelve month average price and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. In Gabon, the price as of December 31, 2011, was $110.08 per bbl. In the United States, the price as of December 31, 2011, was $78.89 per bbl of oil and $5.439 per Mcf of gas. See Note 16 to the Company's consolidated financial statements for certain additional information concerning the proved reserves of the Company.

**Drilling History**

In 2011, the Company drilled three wells as follows: two development wells in the Granite Wash formation in North Texas, and one exploratory well in the Middle Bakken and lower formations of the East Poplar unit in Roosevelt County, Montana.

| | Domestic | | | | | | International | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | | | Net | | | Gross | | | Net | | |
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| Exploratory Wells | | | | | | | | | | | | |
| Productive | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.0 | 0.0 | 0.0 | 0.3 |
| Dry | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.0 | 4.0 | 0.0 | 0.3 | 2.6 |
| In progress | 1.0 | 0.0 | 0.0 | 0.7 | 0.0 | 0.0 | 0.0 | 1.0 | 0.0 | 0.0 | 0.3 | 0.0 |
| Development Wells | | | | | | | | | | | | |
| Productive | 1.0 | 0.0 | 0.0 | 1.0 | 0.0 | 0.0 | 0.0 | 3.0 | 2.0 | 0.0 | 0.9 | 0.6 |
| Dry | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| In progress | 1.0 | 0.0 | 0.0 | 1.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Wells | 3.0 | 0.0 | 0.0 | 2.7 | 0.0 | 0.0 | 0.0 | 5.0 | 7.0 | 0.0 | 1.5 | 3.5 |

**Acreage and Productive Wells**

Below is the total acreage under lease and the total number of productive oil and gas wells of the Company as of December 31, 2011:

| | United States | | International | |
|---|---|---|---|---|
| | Gross | Net(1) | Gross | Net(1) |
| | (Acreage in thousands) | | | |
| Developed acreage | 7.3 | 1.4 | 28.7 | 8.1 |
| Undeveloped acreage | 27.7 | 18.4 | 2411.4 | 912.5 |
| Productive gas wells | 7.0 | 1.6 | 0.0 | 0.0 |
| Productive oil wells | 3.0 | 0.4 | 11.0 | 3.1 |

(1) Net acreage and net productive wells are based upon the Company's working interest in the properties.

The leases in which we hold an interest in undeveloped acreage with minimum remaining terms are not material to us.

**Office Space**

The Company leases its offices in Houston, Texas (approximately 19,700 square feet), in Port Gentil, Gabon (approximately 11,300 square feet) and in Luanda, Angola (approximately 6,000 thousand square feet), which management believes are adequate for the Company's operations.

**Item 3. Legal Proceedings**

The Company is currently not a party to any material litigation.

**Item 4. Mine Safety Disclosures**

Not applicable.

## PART II

### Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

**General**

The Company's common stock is traded on the New York Exchange under the symbol EGY. The following table sets forth the range of high and low sales prices of the common stock for the periods indicated.

| Period | High | Low |
|---|---|---|
| **2010:** | | |
| First Quarter | $4.99 | $3.93 |
| Second Quarter | 6.24 | 4.31 |
| Third Quarter | 6.25 | 5.07 |
| Fourth Quarter | 8.17 | 5.55 |
| **2011:** | | |
| First Quarter | $8.40 | $6.53 |
| Second Quarter | 7.83 | 5.29 |
| Third Quarter | 7.36 | 4.68 |
| Fourth Quarter | 7.50 | 4.57 |

On February 29, 2012 the last reported sale price of the common stock on the New York Stock Exchange was $7.89 per share.

As of February 29, 2012 there were approximately 12,000 holders of record of the Company's common stock.

**Dividends**

The Company has not paid cash dividends and does not anticipate paying cash dividends on the common stock in the foreseeable future.

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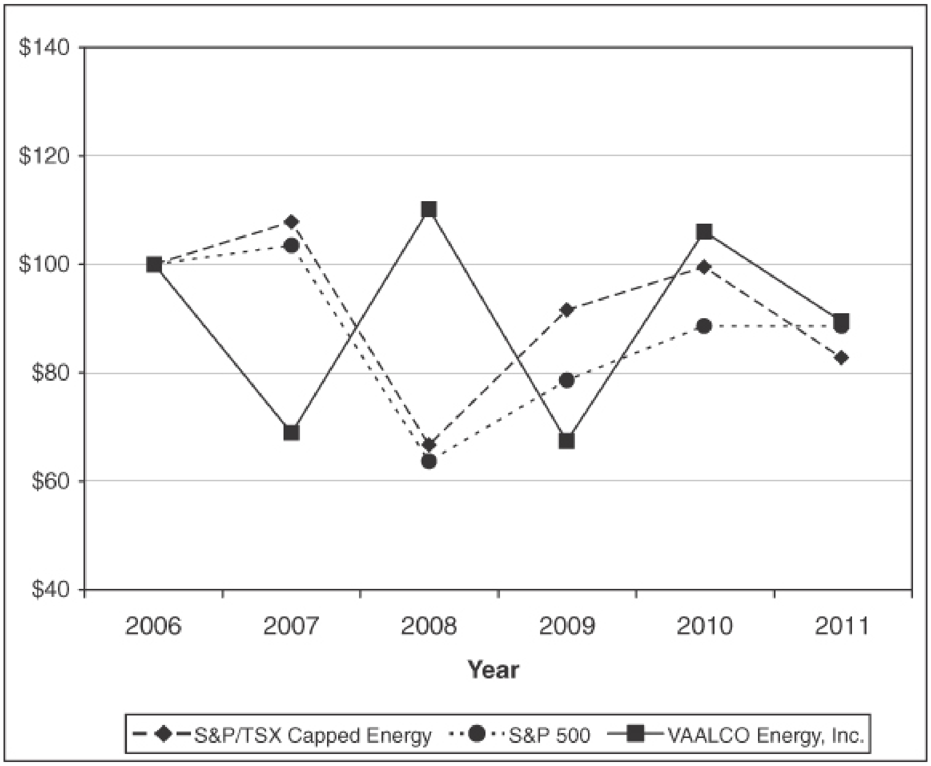
**Performance Graph**

The following graph compares the yearly percentage change in the Company's cumulative total stockholder return on its common shares with the cumulative total return of the S&P 500 Index and the S&P/ TSX Capped Energy Index. For this purpose, the yearly percentage change in the Company's cumulative total stockholder return is calculated by dividing (a) the sum of the dividends paid during the "measurement period," and the difference between the price for the Company's shares at the end and the beginning of the measurement period, by (b) the price for the Company's common shares at the beginning of the measurement period. "Measurement period" means the period beginning at the market close on the last trading day before the beginning of the Company's fifth preceding fiscal year, through and including the end of the Company's most recently completed fiscal year. The Corporation first became listed on the New York Stock Exchange on October 12, 2006.




| | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|
| S&P/TSX Capped Energy | $100 | $108 | $ 67 | $92 | $100 | $83 |
| S&P 500 Composite | $100 | $104 | $ 64 | $79 | $ 89 | $89 |
| VAALCO Energy, Inc. | $100 | $ 69 | $110 | $67 | $106 | $89 |

**Securities Authorized for Issuance under Equity Compensation Plans**

The following table provides information as of December 31, 2011 regarding the number of shares of common stock that may be issued under the Company's compensation plans. Please refer to Note 4 to the consolidated financial statements for additional information on stock based compensation.

| Plan Category | Number of securities to be issued upon exercise of outstanding options, warrants and rights | Weighted-average exercise price of outstanding options, warrants and rights | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 2,558,668 | $ 4.39 | 7,316 |
| Equity compensation plans not approved by security holders | 1,246,748 | $ 6.54 | 1,375,530 |
| Total | 3,805,416 | $ 5.10 | 1,382,846 |

**Issuer Purchases of Equity Securities for Year Ended December 31, 2011**

The Company did not purchase any shares in the year ended December 31, 2011.

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**Item 6. Selected Financial Data**

The following table sets forth, as of the dates and for the periods indicated, selected financial information about the Company. The financial information for each of the five years in the period ended December 31, 2011 has been derived from the Company's Consolidated Financial Statements for such periods. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of the Company's future results.

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| | (In thousands, except per share amounts) | | | | |
| Total revenues | $ 210,436 | $ 134,472 | $ 115,298 | $ 169,525 | $ 125,044 |
| Income (loss) from continuing operations | $ 40,562 | $ 42,387 | $ (4,144) | $ 35,733 | $ 23,532 |
| Net income (loss) attributable to VAALCO Energy, Inc. | $ 34,145 | $ 37,340 | $ (7,889) | $ 29,722 | $ 19,103 |
| Basic income (loss) per common share from continuing operations | $ 0.60 | $ 0.66 | $ (0.14) | $ 0.51 | $ 0.32 |
| Diluted income (loss) per common share from continuing operations | $ 0.59 | $ 0.65 | $ (0.14) | $ 0.50 | $ 0.32 |
| Total assets | $ 275,015 | $ 238,400 | $ 202,999 | $ 252,030 | $ 186,558 |
| Total debt | $ — | $ — | $ — | $ 5,000 | $ 5,000 |

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

## INTRODUCTION

The Company's results of operations are dependent upon the difference between prices received for its oil and gas production and the costs to find and produce such oil and gas. Oil and gas prices have been and are expected in the future to be volatile and subject to fluctuations based on a number of factors beyond the control of the Company.

The Company operates the Etame, Avouma, South Tchibala and Ebouri fields on behalf of a consortium of five companies offshore of the Republic of Gabon. Production commenced from the Etame field in 2002 and was subsequently expanded through additional development wells in 2004, 2005 and 2010. In 2006, the Company developed the Avouma and South Tchibala fields by setting a platform and tying the field back to the FPSO via a pipeline. Oil production commenced from the Avouma and South Tchibala fields in January 2007. Oil production began in January 2009 from the Ebouri field utilizing a platform that was installed in August 2008 and connected to the FPSO by pipeline. There were eleven wells on production from the four offshore fields at the end of 2011. Additional wells are planned to be drilled on the block in 2012.

In the United States, the Company acquired a 640 acre lease (640 net acre) in North Texas in the Granite Wash formation in 2010, as well as a 480 acre (480 net acre) lease in the Granite Wash formation in Hemphill County, North Texas in 2011. In addition, the Company acquired a 5,200 acre (3,640 net acre) lease in the Middle Bakken formation in Sheridan County, Montana, and 22,000 acre (14,300 net acre) lease in the Bakken and deeper formations in Roosevelt County, Montana in 2011. Production commenced from the first Granite Wash well on the initial acreage in August 2011. In November 2011, the Company commenced drilling a second well on the initial Granite Wash formation lease. The well landed in the objective reservoir in February 2012. Subject to successful fracking in March 2012, we expect production to begin soon thereafter. Exploratory drilling on one of the Montana properties began in December 2011. The Company expects to drill additional wells on both Montana properties in 2012.

## CRITICAL ACCOUNTING POLICIES

The following describes the critical accounting policies used by the Company in reporting its financial condition and results of operations. In some cases, accounting standards allow more than one alternative accounting method for reporting, such is the case with accounting for oil and gas activities described below. In those cases, the Company's reported results of operations would be different should it employ an alternative accounting method.

### Successful Efforts Method of Accounting for Oil and Gas activities

The SEC prescribes in Regulation S-X the financial accounting and reporting standards for companies engaged in oil and gas producing activities. Two methods are prescribed: the successful efforts method and the full cost method. Like many other oil and gas companies, the Company has chosen to follow the successful efforts method. Management believes that this method is preferable, as the Company has focused on exploration activities wherein there is risk associated with future success and as such earnings are best represented by attachment to the drilling operations of the Company. Costs of successful wells, development dry holes and leases containing productive reserves are capitalized and amortized on a unit-of-production basis over the life of the related reserves. Other exploration costs, including geological and geophysical expenses applicable to undeveloped leasehold, leasehold expiration costs and delay rentals are expensed as incurred.

In accordance with the successful efforts method of accounting, the Company reviews proved oil and gas properties for indications of impairment whenever events or circumstances indicate that the carrying value of its oil and gas properties may not be recoverable. When it is determined that an oil and gas property's estimated future net cash flows will not be sufficient to recover its carrying amount, an impairment charge must be recorded to reduce the carrying amount of the asset to its estimated fair value. This may occur if a field contains lower than anticipated reserves or if commodity prices fall below a level that significantly effects anticipated future cash flows on the field.

**Impairment of Unproved Property**

The Company evaluates its unproved properties for impairment on a property-by-property basis. The majority of the Company's unproved property consists of acquisition costs related to its undeveloped acreage both in Angola and in the United States. On at least a quarterly basis, management reviews the unproved property for indicators of impairment based on the Company's current exploration plans with consideration given to results of any drilling and seismic activity during the period and known information regarding exploration activity by other companies on adjacent blocks. See Item 2—Properties and Note 7 to the consolidated financial statements for further information on the Company's exploration plans in Angola.

In Angola, any adverse developments related to the Company's ability to further extend the drilling obligation date, if necessary, could result in an impairment of the Company's unproved properties and other assets with a carrying value of approximately $11.0 million.

In the United States, the Company recorded an impairment loss of $5.0 million in 2011, to write down the value of its first Granite Wash formation well to its estimated fair value.

**CAPITAL RESOURCES AND LIQUIDITY**

**Cash Flows**

Net cash provided by operating activities for 2011 was $89.6 million, as compared to $45.5 million in 2010 and $23.5 million in 2009. The increase in cash provided by operating activities in 2011 was primarily due to a $32.5 million positive variance in changes in operating assets and liabilities in 2011 compared to 2010 and increased non-cash charges to net income of $13.4 million in 2011 compared to 2010. The increase in cash provided by operating activities in 2010 versus 2009 was primarily due to net income of $42.4 million in 2010 versus net loss of $4.1 million in 2009.

Net cash used in investing activities in 2011 was $28.4 million, compared to net cash used in investing activities for 2010 of $39.4 million and net cash used in investing activities in 2009 of $49.0 million. In 2011, the Company paid $32.0 million for capital expenditures, partly offset by a $3.6 million release of restricted cash. The Company paid $40.0 million for capital expenditures in 2010, partially offset by a $0.6 million release of restricted cash. In 2009, the Company paid $27.9 million for capital expenditures and $33.4 million in exploration dry hole costs, partially offset by a $6.6 million release of restricted cash and a $5.7 million payment pursuant to a realignment agreement whereby a joint venture partner in Gabon paid its proportionate share of costs, which reduced the Company's property and equipment expenditures.

In 2011, cash used in financing activities was $5.3 million consisting of distributions to a noncontrolling interest owner of $7.2 million partially offset by proceeds from the issuance of common stock upon the exercise of options of $1.9 million. In 2010, cash used in financing activities was $5.5 million consisting of distributions to a noncontrolling interest owner of $6.0 million partially offset by proceeds from the issuance of common stock upon the exercise of options of $0.5 million. In 2009, cash used in financing activities was $19.4 million, consisting primarily of purchase of treasury shares of $10.1 million, debt repayment of $5.0 million and distributions to a noncontrolling interest owner of $6.0 million partially offset by proceeds from the issuance of common stock of $1.8 million.

In recent history, the Company's primary source of capital resources has been from cash flows from operations. On December 31, 2011, the Company had cash balances of $137.1 million and restricted cash of $12.2 million. The Company believes that these cash balances combined with cash flow from operations will be sufficient to fund the Company's 2012 capital expenditure budget, which is expected to total approximately

$75.0 million to further develop the Etame Marin block offshore Gabon with a four well drilling program, an exploration well in the Mutamba Iroru onshore Gabon block, completion of the development well in the Granite Wash formation in Texas and four wells on the Middle Bakken leases in Montana. The Company invests cash not required for immediate operational and capital expenditure needs in short-term bankers acceptance and money market instruments primarily with JPMorgan Chase & Co. The Company does not invest in the asset-backed commercial paper market which has been subject to a liquidity crisis over the last few years. As operator of the Etame, Avouma, South Tchibala and Ebouri fields, the Company enters into project related activities on behalf of its working interest partners. The Company generally obtains advances from its partners prior to significant funding commitments.

**Capital Expenditures**

In 2011, the Company invested $33.0 million in property and equipment additions, primarily associated with $9.5 million to acquire leases in the United States, $14.9 million to drill three wells in the United States, and $7.4 million primarily for offshore platform modifications and production facilities in Gabon. During 2010, the Company invested $40.5 million in property and equipment additions (including amounts carried in accounts payable and excluding exploration dry hole costs), primarily associated with the drilling of three development wells in the Etame Marin block offshore Gabon totaling $29.3 million. In addition, one successful exploration well was drilled in the Southeast Etame area of the Etame Marin block at a cost of $8.0 million, and the Company invested in a Granite Wash formation lease in Texas ($2.2 million) and a second extension of the Mutamba Iroru block onshore Gabon ($1.2 million). During 2009, the Company invested $22.3 million in property and equipment additions (including amounts carried in accounts payable and excluding exploration dry hole costs), primarily associated with the drilling of the three wells in the Ebouri field (the appraisal well plus the two development wells drilled from the Ebouri platform) totaling $16.7 million. Additionally, the Company's share of the leasehold bonus associated with the Etame Marin block exploration period extension totaled $1.4 million.

**Oil and Gas Exploration Costs**

As described above, the Company uses the "successful efforts" method of accounting for its oil and gas exploration and development costs. All expenditures related to exploration, with the exception of costs of drilling exploration wells, are charged as an expense when incurred. The costs of exploration wells are capitalized pending determination of whether commercially producible oil and gas reserves have been discovered. If the determination is made that a well did not encounter potentially economic oil and gas quantities, the well costs are charged as an expense. In 2011, the Company incurred $5.7 million in exploration expense, including $2.0 million spent in the United States and Canada (primarily exploration well costs), $1.9 million offshore Gabon (primarily seismic acquisition costs), $0.8 million onshore Gabon (seismic reprocessing costs), $0.4 million in the United Kingdom (residual exploration well costs), and $0.6 million in Angola (exploration well preparation costs). In 2010, the Company incurred $6.8 million in exploration expense, including $2.6 million on the Omangou unsuccessful exploration well offshore Gabon, $1.4 million for seismic costs in the Etame Marin block offshore Gabon, onshore Gabon exploration expense of $0.7 million, and $0.9 million in Angola. In 2009, the Company incurred $36.5 million in exploration expense including $33.4 million of dry hole costs (British North Sea—$9.6 million, the Etame Marin block offshore Gabon—$3.0 million and the Mutamba Iroru block onshore Gabon—$20.8 million). The Company spent the remaining $3.1 million primarily on seismic processing costs in the Etame Marin block ($0.6 million), Mutamba Iroru block ($0.9 million) and in Angola ($1.4 million).

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**Contractual Obligations**

The table below summarizes the Company's net share of obligations and commitments at December 31, 2011:

**Payment Period**

| (in thousands $) | 2012 | 2013 | 2014 | 2015 | 2016 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Operating leases(1) | $8,108 | $6,226 | $5,258 | $3,696 | $434 | $ 651 | $ 24,373 |

1. The Company is guarantor of a lease for the FPSO utilized in Gabon, which has remaining obligations of $62.2 million. The Company's share of these payments is included in the table above. The Company can cancel the lease anytime after September 14, 2015, with 12 months prior notice. Approximately 72% of the payment is co-guaranteed by the Company's partners in Gabon. In addition to the FPSO amounts, the schedule includes the Company's share of its other lease obligations.

In addition to the contractual obligations described above, the Company entered into a sixth exploration period extension during 2009 and is required to spend $5.3 million for its share of two exploration wells and acquire/process 150 square kilometers of 3-D seismic on the Etame Marin block by July 2014. One of the two exploration commitment wells was drilled in 2010 on the Omangou prospect at a cost of $8.6 million ($2.6 million net to the Company). The seismic obligation was met with the acquisition of 223 square kilometers of 3-D seismic in 2011. The remaining obligation is the drilling of one exploration well.

As part of securing the second ten year production license with the government of Gabon, the Company agreed in principle to a cash funding arrangement for the eventual abandonment of the offshore wells, platforms and facilities. The agreement is not yet signed, but calls for annual funding for the next seven years at 12.14% of the abandonment estimate and 5.0% for the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The funding is expected to begin in 2012 after the agreement is finalized. The abandonment estimate for this purpose is estimated to be approximately $14.0 million net to the Company on an undiscounted basis. As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company's balance sheet.

The Company also entered into the second exploration period for the Mutamba Iroru block which requires the Company to reprocess 400 kilometers of 2-D seismic and drill one exploration well by May 2012. The seismic reprocessing was largely completed in 2011. The Company is expected to request an extension period in the first quarter of 2012 as the rig to drill the exploration well is not expected to be available until the third quarter of 2012. However, the Company can provide no assurances that such a request will be granted.

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic data, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Following the decree, the Company and the government of Angola have been working together to obtain a replacement partner. Options to amend the two-well commitment are also being discussed with the Angolan government. Because of the uncertainty surrounding the outcome of the discussions with the Angolan government, the Company recorded a full allowance of $4.4 million in 2011 against the accounts receivable from partners for the amounts owed to the Company above its 40% working interest plus the 10% carried interest. In early 2012, the Angolan government granted a further one year extension for drilling the two exploration commitment wells in accordance with the production sharing contract.

Due to the timing uncertainty of obtaining a replacement partner and the outcome of discussions regarding modifying the drilling well commitments required by the production sharing contract, a time extension may be necessary beyond the current expiration date of November 30, 2012. The Company can provide no assurances that such an extension will be granted, if necessary. If the government of Angola were to deny a request for a further time extension, the Company may be required to impair its leasehold costs and other investments totaling $11.0 million as of December 31, 2011. The Company may also be required to pay the Angolan government $10.0 million in lieu of drilling the two exploration commitment wells.

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. Pursuant to the terms of the acquisition, the Company is required to drill three wells at its sole cost, one of which must be drilled by June 1, 2012 and the remaining two wells must be drilled by the end of 2012. A vertical exploration well was spudded in December 2011 to evaluate the formations which meets the time requirement for drilling the first well. Two additional wells are expected to be drilled on this property in 2012 in accordance with the terms of the agreement.

The Company is carrying $14.5 million of asset retirement obligations as of December 31, 2011, representing the present value of these obligations as of that date.

## RESULTS OF OPERATIONS

### Year Ended December 31, 2011 Compared to Years Ended December 31, 2010 and 2009

#### Revenues

Total oil and gas sales for 2011 were $210.4 million as compared to $134.5 million and $115.3 million for 2010 and 2009, respectively. In 2011, the Company sold approximately 1,864,000 bbls at an average price of $111.98 per bbl from the Etame Marin block in Gabon, and approximately 4,000 bbls and 255 MMcf in the United States at an average price of $79.71 per bbl and $5.23 per Mcf, respectively. In 2010, the Company sold approximately 1,714,000 bbls at an average price of $78.38 per bbl from the Etame Marin block with revenues from the United States of $0.1 million. In 2009, the Company sold approximately 1,935,000 bbls at an average price of $59.54 per bbl from the Etame Marin block with revenues from the United States of $0.1 million.

#### Operating Costs and Expenses

Production expense for 2011 was $26.7 million as compared to $22.1 million and $22.0 million for 2010 and 2009, respectively. The higher production expense in 2011 is the result of higher sales volumes and higher Domestic Market Obligation payments to the Republic of Gabon. In the aggregate, production expenses in 2010 were nearly the same as in 2009. When compared to 2009, 2010 operating costs and expenses included the Ebouri well workover ($1.5 million), partially offset by lower sales volumes which reduced production expenses. Any production expenses associated with unsold crude oil inventory are capitalized.

Exploration expense for 2011 was $5.7 million as compared to $6.8 million and $36.5 million for 2010 and 2009, respectively. In 2011, exploration expense was primarily comprised of $2.0 million spent in the United States and Canada (primarily exploration well costs), $1.9 million offshore Gabon (primarily seismic acquisition costs), $0.8 million onshore Gabon (seismic reprocessing costs), $0.4 in the United Kingdom (residual exploration well costs), and $0.6 million in Angola (exploration well preparation costs). In 2010, exploration expense was primarily comprised of $2.6 million for the Omangou unsuccessful exploration well offshore Gabon, $1.4 million for seismic costs in the Etame Marin block offshore Gabon, onshore Gabon exploration expense of $0.7 million, and $0.9 million in Angola primarily for geotechnical studies. In 2009, the Company spent $33.4 million on four unsuccessful exploration wells including the North Etame prospect offshore Gabon ($3.0 million), two wells on the Mutamba Iroru block onshore Gabon ($20.8 million) and a well on Block 48/25c in the British North Sea ($9.6 million). Additionally, in 2009 the Company spent $3.1 million primarily associated with seismic processing costs in Block 5 in Angola and the Mutamba Iroru block in Gabon.

Depreciation, depletion and amortization expense was $25.6 million for 2011, and was $20.0 million and $20.8 million for 2010 and 2009, respectively. Depletion, depreciation and amortization expense increased in 2011 versus 2010 due to both higher sales volumes and higher depletion rates. The 2011 depletion rates for the Ebouri field averaged $21.51 per bbl, Avouma and South Tchibala fields averaged $7.94 per bbl, and the Etame field averaged $7.94 per bbl. Depletion rates for the Granite Wash well averaged $7.75 per Mcf.

General and administrative expense for 2011 was $10.4 million as compared to $7.4 million and $9.6 million for 2010 and 2009, respectively. The increase in general and administrative expense for 2011 versus 2010 was primarily due to $3.7 million lower overhead reimbursement associated with lower capital expenditures offshore Gabon.

The decrease in general and administrative expense for 2010 versus 2009 was primarily due to $2.1 million of increased overhead reimbursement associated with the extensive drilling program in offshore Gabon and a decrease in retirement benefits of $1.0 million.

During 2011, the Company incurred $2.2 million of stock based compensation compared to $1.8 million incurred in 2010 and $1.8 million incurred in 2009. In each of the three years, the Company benefited from overhead reimbursement associated with production and development operations on the Etame Marin block.

During 2011, the Company recorded a bad debt provision of $4.4 million related to the uncertainty in collecting its joint venture receivable in Angola.

Furthermore, during 2011, the Company recorded an impairment loss of $5.0 million to bring down its investment in the Granite Wash formation of North Texas to its fair value.

Other operating income for 2009 was $6.5 million. For 2011 and 2010, no amounts were recorded for other operating income. The other operating income recorded in 2009 was attributable to receipt of proceeds from a joint venture partner that originally elected to not participate in two wells drilled in the Ebouri field, offshore Gabon. The partner later elected to participate and paid for their proportionate share of the capital expenditures for the wells. The $6.5 million payment received represents the Company's share of an agreed risk premium benefiting the joint venture partners that originally participated in those two wells.

**Operating Income**

Operating income for 2011 was $132.6 million as compared to a $78.1 million and $33.0 million for 2010 and 2009, respectively. The significant increase in operating income in 2011 versus 2010 was attributable to both higher sales volumes and higher average crude sales prices of $111.93 per bbl, an increase of $33.55 per bbl.

The significant increase in operating income in 2010 versus 2009 was primarily attributable to the higher average crude sales price of $78.38 per bbl, an increase of $18.84 per bbl, and a year to year decrease in exploration expense totaling $29.7 million. The decrease in exploration expense reflects less dry hole expense incurred in 2010 versus 2009.

**Other Income (Expense)**

Interest income for 2011 was $0.2 million compared to $0.2 million and $0.7 million in 2010 and 2009, respectively. All 2011, 2010, and 2009 amounts represent interest earned and accrued on cash balances and funds in escrow.

No interest expense was recorded in 2011 or 2010. Interest expense of $0.5 million was recorded in 2009 in connection with the financings from the IFC for use on Etame Marin block activities.

Other income for 2011 was $1.3 million, as compared to other expense of $0.6 million in 2010 and other expense of $0.5 million in 2009. Other income and expense is primarily the result of foreign currency transaction gains and losses from the Company's foreign operations.

**Income Taxes**

In 2011, the Company incurred $93.5 million of income taxes, as compared to $35.3 million incurred in 2010, and $36.9 million in 2009. All income tax expenses were associated with the Etame Marin block production, and were incurred in Gabon. The higher income tax expense in Gabon in 2011 is a function of higher sales volumes, significantly higher oil prices, and modest costs incurred, resulting in higher profit oil barrels subject to taxes. After deducting royalty and cost oil, the remaining barrels are profit oil barrels which bear income tax. At 2011 production rates, the income tax paid on profit oil barrels was 55%. The slightly lower income taxes incurred in 2010 versus 2009 was a function of lower sales quantities largely offset by higher crude oil sales prices.

**Net Income (Loss)**

Net income for 2011 was $40.6 million, compared to net income in 2010 of $42.4 million, and net loss in 2009 of $4.1 million. The decrease in net income in 2011, despite higher sales volumes and average oil prices, was due to higher income taxes and one-time charges for bad debt expense and impairment losses. The increase in net income in 2010 versus 2009 is attributable to the increased crude oil sales prices and a lesser amount of unsuccessful exploration well costs incurred in 2010.

Income attributable to the noncontrolling interest in the Gabon subsidiary was $6.4 million, $5.0 million and $3.7 million in 2011, 2010, and 2009, respectively.

**NEW ACCOUNTING PRONOUNCEMENTS**

For a discussion of new accounting pronouncements, see Note 3 to the consolidated financial statements.

**OFF BALANCE SHEET ARRANGEMENTS**

For a discussion of off balance sheet arrangements associated with the guarantee by the Company of the charter payments for the FPSO located in Gabon, see Note 7 to the consolidated financial statements.

## Item 7A. Quantitative and Qualitative Disclosures About Market Risk

**Market Risk**

The Company's major market risk exposure continues to be the prices applicable to its oil and gas production. Sales prices are primarily driven by the prevailing market price. Historically, prices received for oil and gas production have been volatile and unpredictable.

**Foreign Exchange Risk**

Our results of operations and financial condition are affected by currency exchange rates. While oil sales are denominated in U.S. dollars, portions of our operating costs in Gabon are denominated in the local currency. A weakening U.S. dollar will have the effect of increasing operating costs while a strengthening U.S. dollar will have the effect of reducing operating costs. The Gabon local currency is tied to the Euro. The exchange rate between the Euro and the U.S. dollar has fluctuated widely in response to international political conditions, general economic conditions and other factors beyond our control.

**Interest Rate Risk**

At December 31, 2011, the Company did not have any debt and thus no exposure to interest rate risk on debt. Interest earned on cash investments is immaterial.

**Commodity Price Risk**

The Company had no derivatives in place as of the date of this report, or throughout 2011, 2010 or 2009.

## Item 8. Financial Statements and Supplementary Data

The information required here is included in the report as set forth in the "Index to Consolidated Financial Information" on page F-1.

## Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

## Item 9A. Controls and Procedures

**Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures**

The Company maintains disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by the Company in the reports it files or submits under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to the Company's management, including the Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure. The Company's management, including the Company's principal executive officer and principal financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Based on that evaluation, the Company's principal executive officer and principal financial officer have concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this Annual Report on Form 10-K. There were no changes in the Company's internal controls over financial reporting that occurred during the Company's last quarter that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

**Management's Annual Report on Internal Control Over Financial Reporting**

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of the Company's management, including the Company's principal executive and principal financial officers, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework"). Based on this evaluation under the COSO Framework which was completed on March 12, 2012, management concluded that its internal control over financial reporting was effective as of December 31, 2011.

The Company's internal control over financial reporting as of December 31, 2011 has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audited the Company's consolidated financial statements as of and for the year ended December 31, 2011, as stated in their report which follows.

**Changes in Internal Control Over Financial Reporting**

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) occurred during the fourth quarter of our fiscal year ended December 31, 2011 that has materially affected, or is reasonable likely to materially affect, our internal control over financial reporting.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Stockholders of VAALCO Energy, Inc. and subsidiaries:
Houston, Texas

We have audited the internal control over financial reporting of VAALCO Energy, Inc. and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company, and our report dated March 12, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 12, 2012

### Item 9B. Other Information

The Company has disclosed all information required to be disclosed in a current report on Form 8-K during the year ended December 31, 2011 in previously filed reports on Form 8-K.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item will be included in the Company's proxy statement for its 2012 annual meeting, which will be filed with the Commission within 120 days of December 31, 2011, and which is incorporated herein by reference.

### Item 11. Executive Compensation

Information required by this item will be included in the Company's proxy statement for its 2012 annual meeting, which will be filed with the Commission within 120 days of December 31, 2011, and which is incorporated herein by reference.

### Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by this item under Item 403 of Regulation S-K concerning the security ownership of certain beneficial owners and management will be included in the Company's proxy statement for its 2012 annual meeting, which will be filed with the Commission within 120 days of December 31, 2011, and which is incorporated herein by reference. Please see "Item 5—Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchase of Equity Securities" for information on securities that may be issued under the Company's stock incentive plans.

### Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be included in the Company's proxy statement for its 2012 annual meeting, which will be filed with the Commission within 120 days of December 31, 2011, and which is incorporated herein by reference.

### Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference from the Company's definitive proxy statement for its 2012 annual meeting, which will be filed with the Commission within 120 days of December 31, 2011, and which is incorporated herein by reference.

## PART IV

**Item 15. Exhibits and Financial Statement Schedules**

(a) 1. The following is an index to the financial statements that are filed as part of this Form 10-K.

VAALCO ENERGY, INC. AND SUBSIDIARIES



(a) 2. Schedules are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.

(a) 3. Exhibits:

3. Articles of Incorporation and Bylaws

| | |
|---|---|
| 3.1(a) | Restated Certificate of Incorporation |
| 3.2(a) | Certificate of Amendment to Restated Certificate of Incorporation |
| 3.3(j) | Amended and Restated Bylaws |

10. Material Contracts

| | |
|---|---|
| 10.1(b) | Indemnity Agreement entered into among the Company and certain of its officers and directors listed therein. |
| 10.2(c) | Exploration and Production Sharing contract between the Republic of Gabon and VAALCO Gabon (Etame), Inc. dated July 7, 1995. |
| 10.3(c) | Deed of Assignment and Assumption between VAALCO Gabon (Etame), Inc., VAALCO Energy (Gabon), Inc. and Petrofields Exploration & Development Co., Inc. dated September 28, 1995. |
| 10.4(d) | Letter of Intent for Etame Marin block, Offshore Gabon dated January 22, 1998 between the Company and Western Atlas International, Inc. |
| 10.5(e) | 2001 Stock Incentive Plan dated August 16, 2001. |
| 10.6(f) | Trustee and Paying Agent Agreement by and between VAALCO Gabon (Etame), Inc., J.P. Morgan Trustee and Depositary Company Limited and JPMorgan Chase Bank, London Branch, dated June 26, 2002. |
| 10.7(g) | 2003 Stock Incentive Plan dated December 16, 2003. |

| | |
|---|---|
| 10.8(h) | Exploration and Production Sharing contract between the Republic of Gabon and VAALCO Production (Gabon), Inc., Permit Mutamba Iroru dated November 11, 2005. |
| 10.9(i) | 2007 Stock Incentive Plan dated May 1, 2007. |
| 10.11(k) | Settlement Agreement, dated as of May 23, 2008 by and among the Company and Nanes Delorme Partners I LP, Nanes Balkany Partners LLC, Nanes Balkany Management LLC, Julien Balkany and Daryl Nanes. |

21. Subsidiaries of the Company

| | |
|---|---|
| 21.1 | Subsidiaries of the Registrant |

23. Consents of Experts and Counsel

| | |
|---|---|
| 23.1 | Consent of Deloitte & Touche LLP |
| 23.2 | Consent of Netherland, Sewell & Associates, Inc. |

31. Rule 13a-14(a) Certifications

| | |
|---|---|
| 31.2 | Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certification pursuant to section 302 of the Sarbanes-Oxley Act of 2002 |

32. Section 1350 Certifications

| | |
|---|---|
| 32.1 | Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act Of 2002 |
| 32.2 | Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act Of 2002 |

99. Reserve Report

| | |
|---|---|
| 99.1 | Report of Netherland, Sewell & Associates, Inc. |

101. Interactive Data Files

| | |
|---|---|
| 101.INS | XBRL Instance Document.* |
| 101.SCH | XBRL Taxonomy Schema Document.* |
| 101.CAL | XBRL Calculation Linkbase Document. |
| 101.DEF | XBRL Definition Linkbase Document.* |
| 101.LAB | XBRL Label Linkbase Document.* |
| 101.PRE | XBRL Presentation Linkbase Document.* |

(a) Filed as an exhibit to the Company's Registration Statement on Form S-3 filed with the Commission on July 15, 1998, and hereby incorporated by reference herein.

(b) Filed as an exhibit to the Company's Form 10 (File No. 0-20928) filed on December 3, 1992, as amended by Amendment No. 1 on Form 8 on January 7, 1993, and by Amendment No. 2 on Form 8 on January 25, 1993, and hereby incorporated by reference herein.

(c) Filed as an exhibit to the Company's Form 10-QSB for the quarterly period ended September 30, 1995, and hereby incorporated by reference herein.

(d) Filed as an exhibit to the Company's Form 10-KSB for the annual period ended December 31, 1996, and hereby incorporated by reference herein.

(e) Filed as an exhibit to the Company's Registration Statement Form S-8 filed with the Commission on August 18, 2001, and incorporated by reference herein.

(f) Filed as an exhibit to the Company's Form 10-QSB for the quarterly period ended June 30, 2002, and hereby incorporated by reference herein.

(g) Filed as an exhibit to Form10-KSB for the annual period ended December 31, 2004, and hereby incorporated by reference herein.

(h) Filed as an exhibit to Form 10-K for the annual period ended December 31, 2005, and hereby incorporated by reference herein.

(i) Filed as an exhibit to the Company's Registration Statement Form S-8 filed with the Commission on July 25, 2007 and hereby incorporated by reference herein.

(j) Filed as an exhibit to Company's Report on Form 8-K filed with the Commission on December 12, 2007, and hereby incorporated by reference herein.

(k) Filed as an exhibit to Company's Report on Form 8-K filed with the Commission on May 28, 2008, and hereby incorporated by reference herein.

* Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability.

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## SIGNATURES

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

VAALCO ENERGY, INC.
(Registrant)

By /s/ GREGORY R. HULLINGER
**Gregory R. Hullinger**
**Chief Financial Officer**

Dated March 12, 2012

**In accordance with the Exchange Act, this report has been signed below on the 12th day of March, 2012, by the following persons on behalf of the registrant and in the capacities indicated.**

| | Signature | Title |
|---|---|---|
| By: | /s/ ROBERT L. GERRY, III.<br>**Robert L. Gerry, III.** | Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer) |
| By: | /s/ W. RUSSELL SCHEIRMAN<br>**W. Russell Scheirman** | President, Chief Operating Officer And Director |
| By: | /s/ GREGORY R. HULLINGER<br>**Gregory R. Hullinger** | Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer) |
| By: | /s/ ROBERT H. ALLEN<br>**Robert H. Allen** | Director |
| By: | /s/ LUIGI CAFLISCH<br>**Luigi Caflisch** | Director |
| By: | /s/ O. DONALD CHAPOTON<br>**O. Donald Chapoton** | Director |
| By: | /s/ JOHN J. MYERS, JR.<br>**John J. Myers, Jr.** | Director |
| By: | /s/ FREDERICK W. BRAZELTON<br>**Frederick W. Brazelton** | Director |

**VAALCO ENERGY, INC. AND SUBSIDIARIES**

**INDEX TO CONSOLIDATED FINANCIAL INFORMATION**

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Stockholders of VAALCO Energy, Inc. and subsidiaries:
Houston, Texas

We have audited the accompanying consolidated balance sheets of VAALCO Energy, Inc. and subsidiaries (the “Company”) as of December 31, 2011 and 2010, and the related statements of consolidated operations, equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of VAALCO Energy, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Company adopted new accounting guidance in 2009 related to the estimation of oil and gas reserves.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2012 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Houston, Texas
March 12, 2012

**VAALCO ENERGY, INC. AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEETS**

**(in thousands of dollars, except number of shares and par value amounts)**

| | December 31, 2011 | December 31, 2010 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | **$ 137,139** | $ 81,234 |
| Restricted cash | **1,314** | 14,932 |
| Receivables: | | |
| Trade | **10,087** | 14,068 |
| Accounts with partners, net of allowance of $4.4 million in 2011 | **6,974** | 16,180 |
| Other | **4,239** | 10,412 |
| Crude oil inventory | **757** | 548 |
| Materials and supplies | **235** | 501 |
| Prepayments and other | **2,178** | 1,482 |
| Total current assets | **162,923** | 139,357 |
| Property and equipment—successful efforts method: | | |
| Wells, platforms and other production facilities | **178,653** | 168,139 |
| Undeveloped acreage | **25,344** | 16,692 |
| Work in progress | **20,703** | 8,812 |
| Equipment and other | **4,543** | 2,634 |
| | **229,243** | 196,277 |
| Accumulated depreciation, depletion and amortization | **(129,395)** | (99,457) |
| Net property and equipment | **99,848** | 96,820 |
| Other assets: | | |
| Deferred tax asset | **1,349** | 1,349 |
| Restricted cash | **10,895** | 874 |
| Total Assets | **$ 275,015** | $ 238,400 |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | **$ 25,090** | $ 26,702 |
| Total current liabilities | **25,090** | 26,702 |
| Asset retirement obligations | **14,528** | 13,425 |
| Other liabilities | **2,330** | 2,030 |
| Total liabilities | **41,948** | 42,157 |
| Commitments and contingencies (Note 7) | | |
| VAALCO Energy Inc. shareholders' equity: | | |
| Common stock, $0.10 par value, 100,000,000 authorized shares, 62,376,563 and 62,822,805 shares issued with 5,257,638 and 6,005,547 shares in treasury at Dec. 31, 2011 and 2010, respectively | **6,238** | 6,282 |
| Additional paid-in capital | **66,122** | 64,314 |
| Retained earnings | **180,739** | 146,594 |
| Less treasury stock, at cost | **(23,975)** | (25,665) |
| Total VAALCO Energy Inc. shareholders' equity | **229,124** | 191,525 |
| Noncontrolling interest | **3,943** | 4,718 |
| Total Equity | **233,067** | 196,243 |
| Total Liabilities and Equity | **$ 275,015** | $ 238,400 |

See notes to consolidated financial statements.

**VAALCO ENERGY, INC. AND SUBSIDIARIES**

**STATEMENTS OF CONSOLIDATED OPERATIONS**
**(in thousands of dollars, except per share amounts)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Revenues: | | | |
| Oil and gas sales | **$210,436** | $134,472 | $115,298 |
| Operating costs and expenses: | | | |
| Production expense | **26,731** | 22,112 | 21,978 |
| Exploration expense | **5,708** | 6,813 | 36,464 |
| Depreciation, depletion and amortization | **25,596** | 20,021 | 20,760 |
| General and administrative expense | **10,417** | 7,403 | 9,580 |
| Bad debt expenses | **4,448** | — | — |
| Impairment of proved properties | **4,975** | — | — |
| Other operating income | **—** | — | (6,503) |
| Total operating costs and expenses | **77,875** | 56,349 | 82,279 |
| Operating income | **132,561** | 78,123 | 33,019 |
| Other income (expense): | | | |
| Interest income | **184** | 151 | 654 |
| Interest expense | **—** | — | (450) |
| Other, net | **1,285** | (627) | (465) |
| Total other income (expense) | **1,469** | (476) | (261) |
| Income before income taxes | **134,030** | 77,647 | 32,758 |
| Income tax expense | **93,468** | 35,260 | 36,902 |
| Net income (loss) | **40,562** | 42,387 | (4,144) |
| Less net income attributable to noncontrolling interest | **(6,417)** | (5,047) | (3,745) |
| Net income (loss) attributable to VAALCO Energy, Inc. | **$ 34,145** | $ 37,340 | $ (7,889) |
| Basic net income (loss) per share atributable to VAALCO Energy, Inc. common shareholders | $ 0.60 | $ 0.66 | $ (0.14) |
| Diluted net income (loss) per share attributable to VAALCO Energy, Inc. common shareholders | $ 0.59 | $ 0.65 | $ (0.14) |
| Basic weighted average shares outstanding | **57,048** | 56,466 | 57,407 |
| Diluted weighted average shares outstanding | **57,973** | 57,038 | 57,407 |

See notes to consolidated financial statements

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**VAALCO ENERGY, INC AND SUBSIDIARIES**

**STATEMENTS OF CONSOLIDATED EQUITY**
**(in thousands of dollars)**

| | VAALCO ENERGY, Inc. Shareholders | | | | | |
|---|---|---|---|---|---|---|
| | Common Stock | Additional Paid-In Capital | Retained Earnings | Treasury Stock | Noncontrolling Interest | Total |
| Balance at January 1, 2009 | $ 6,112 | $ 53,983 | $117,205 | $(11,422) | $ 7,914 | $173,792 |
| Proceeds from stock issuance | 45 | 1,726 | — | — | — | 1,771 |
| Stock based compensation | — | 1,841 | — | — | — | 1,841 |
| Treasury Stock Transaction | — | — | — | (10,093) | — | (10,093) |
| Net income (loss) | — | — | (7,889) | — | 3,745 | (4,144) |
| Redemption of rights agreement | — | — | (67) | — | — | (67) |
| Distribution to noncontrolling interest | — | — | — | — | (5,995) | (5,995) |
| Balance at December 31, 2009 | $ 6,157 | $ 57,550 | $109,249 | $(21,515) | $ 5,664 | $157,105 |
| Proceeds from stock issuance | 125 | 4,614 | — | (4,150) | — | 589 |
| Stock based compensation | — | 2,150 | — | — | — | 2,150 |
| Net income | — | — | 37,340 | — | 5,047 | 42,387 |
| Redemption of rights agreement | — | — | 5 | — | — | 5 |
| Distribution to noncontrolling interest | — | — | — | — | (5,993) | (5,993) |
| Balance at December 31, 2010 | $ 6,282 | $ 64,314 | $146,594 | $(25,665) | $ 4,718 | $196,243 |
| Proceeds from stock issuance | 30 | 1,207 | — | — | — | 1,237 |
| Stock based compensation | — | 2,217 | — | — | — | 2,217 |
| Constructive retirement of treasury stock | (74) | (1,616) | — | 1,690 | — | — |
| Net income | — | — | 34,145 | — | 6,417 | 40,562 |
| Distribution to noncontrolling interest | — | — | — | — | (7,192) | (7,192) |
| Balance at December 31, 2011 | $ 6,238 | $ 66,122 | $180,739 | $(23,975) | $ 3,943 | $233,067 |

See notes to consolidated financial statements

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**VAALCO ENERGY, INC. AND SUBSIDIARIES**

**STATEMENTS OF CONSOLIDATED CASH FLOWS**
**(in thousands of dollars)**

| | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net income (loss) | **$ 40,562** | $ 42,387 | $ (4,144) |
| Adjustments to reconcile net income (loss) to net cash provided by operating activities | | | |
| Depreciation, depletion and amortization | **25,596** | 20,021 | 20,760 |
| Unrealized foreign exchange (gain) loss | **25** | (595) | (316) |
| Dry hole costs | **60** | 2,609 | 33,373 |
| Stock based compensation | **2,217** | 1,895 | 1,841 |
| Bad debt provision | **4,448** | — | — |
| Impairment loss | **4,975** | — | — |
| Gain on disposal of assets | **4** | — | — |
| Change in operating assets and liabilities: | | | |
| Trade receivables | **3,981** | (5,893) | 1,338 |
| Accounts with partners | **5,171** | (2,622) | (15,156) |
| Other receivables | **5,560** | (4,557) | (3,159) |
| Crude oil inventory | **176** | (262) | 1,095 |
| Materials and supplies | **266** | (341) | 265 |
| Other long term assets | **—** | 502 | (155) |
| Prepayments and other | **(886)** | (301) | 1,185 |
| Accounts payable and other liabilities | **(2,570)** | (7,328) | (13,434) |
| Net cash provided by operating activities | **89,585** | 45,515 | 23,493 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Decrease in restricted cash | **3,597** | 639 | 6,637 |
| Property and equipment expenditures | **(31,973)** | (40,012) | (61,340) |
| Reimbursement of property and equipment expenditures by partner | **—** | — | 5,737 |
| Net cash used in investing activities | **(28,376)** | (39,373) | (48,966) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Proceeds from the issuance of common stock | **1,888** | 510 | 1,771 |
| Debt repayment | **—** | — | (5,000) |
| Purchase of treasury shares | **—** | — | (10,093) |
| Redemption of rights agreement | **—** | 5 | (66) |
| Distribution to noncontrolling interest | **(7,192)** | (5,993) | (5,994) |
| Net cash used in financing activities | **(5,304)** | (5,478) | (19,382) |
| NET CHANGE IN CASH AND CASH EQUIVALENTS | **55,905** | 664 | (44,855) |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | **81,234** | 80,570 | 125,425 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | **$137,139** | $ 81,234 | $ 80,570 |
| Supplemental disclosure of cash flow information | | | |
| Cash paid for Income taxes | **$ 92,275** | $ 35,777 | $ 34,438 |
| Cash paid for Interest | **$ —** | $ — | $ 599 |
| Supplemental disclosure of non cash investing and financing activities | | | |
| Property and equipment additions incurred during the period but not paid at period end | **$ 6,450** | $ 5,478 | $ 4,363 |
| Receivable from employees for stock option exercise | **$ —** | $ 651 | $ — |

See notes to consolidated financial statements.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

## 1. ORGANIZATION

VAALCO Energy, Inc., a Delaware corporation, is a Houston-based independent energy company principally engaged in the acquisition, exploration, development and production of crude oil and natural gas. As used herein, the terms "Company" and "VAALCO" mean VAALCO Energy, Inc. and its subsidiaries, unless the context otherwise requires. VAALCO owns producing properties and conducts exploration activities as operator of consortiums internationally in Gabon and Angola and has conducted exploration activities as a non-operator in the British North Sea. Domestically, the Company has interests in Texas, Montana, Alabama, and the Louisiana Gulf Coast area.

VAALCO's active subsidiaries include VAALCO Gabon (Etame), Inc., VAALCO Production (Gabon), Inc., VAALCO Angola (Kwanza), Inc., VAALCO Energy (USA), Inc. and VAALCO (UK) North Sea, Limited.

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation—The accompanying consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. The portion of the income and net assets applicable to the non-controlling interest in the majority-owned operations of the Company's Gabon subsidiary is reflected as noncontrolling interest. All transactions within the consolidated group have been eliminated in consolidation.

Cash and Cash Equivalents—For purposes of the statements of consolidated cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash and cash equivalents.

Restricted Cash—Restricted cash includes cash that is contractually restricted. Restricted cash and cash equivalents are classified as a current or non-current asset based on their designated purpose. Current amounts at December 31, 2011 include an escrow account representing the Company's bank guarantees for customs clearance in Gabon ($1.3 million). Long term amounts at December 31, 2011 include the Company's charter payment escrow for the Floating Production Storage and Offloading tanker ("FPSO") in Gabon ($0.8 million), funds restricted to secure the Company's drilling obligation in Block 5 in Angola ($10.0 million), and funds restricted for the abandonment of certain Gulf of Mexico properties ($44,000).

Amounts in restricted cash at December 31, 2010 included an escrow account representing the Company's bank guarantees for customs clearance in Gabon ($4.9 million), as well as funds restricted to secure the Company's drilling obligation in Block 5 in Angola ($10.0 million). Long term amounts at December 31, 2010 included the Company's charter payment escrow for the Floating Production Storage and Offloading tanker ("FPSO") in Gabon ($0.8 million) and for the abandonment of certain Gulf of Mexico properties ($44,000).

The Company invests restricted and excess cash in certificates of deposit and commercial paper issued by banks with maturities typically not exceeding 90 days.

Inventory—Materials and supplies are valued at the lower of cost, determined by the weighted-average method, or market. Crude oil inventories are carried at the lower of cost or market and represent the Company's share of crude oil produced and stored on the FPSO, but unsold. Inventory cost represents the production expenses including depletion.

Income Taxes—VAALCO accounts for income taxes under an asset and liability approach that recognizes deferred income tax assets and liabilities for the estimated future tax consequences of differences between the financial statements and tax bases of assets and liabilities. Valuation allowances are provided against deferred tax assets that are not likely to be realized.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Property and Equipment—The Company follows the successful efforts method of accounting for exploration and development costs. Under this method, exploration costs, other than the cost of exploratory wells, are charged to expense as incurred. Exploratory well costs are initially capitalized until a determination as to whether proved reserves have been discovered. If an exploratory well is deemed to not have found proved reserves, the associated costs are expensed at that time. Other exploration costs, including geological and geophysical expenses applicable to undeveloped leasehold, leasehold expiration costs and delay rentals are expensed as incurred. All development costs, including developmental dry hole costs, are capitalized.

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred by capitalizing the corresponding cost as part of the carrying amount of the long-lived assets.

The Company reviews its oil and gas properties for impairment whenever events or changes in circumstances indicate that the carrying amount of such properties may not be recoverable. When it is determined that an oil and gas property's estimated future net cash flows will not be sufficient to recover its carrying amount, an impairment charge must be recorded to reduce the carrying amount of the asset to its estimated fair value. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations and other factors.

Depletion of wells, platforms, and other production facilities are calculated on a field basis under the unit-of-production method based upon estimates of proved developed producing reserves. Depletion of developed leasehold acquisition costs are provided on a field basis under the unit-of-production method based upon estimates of proved reserves. Undeveloped leasehold acquisition costs are not subject to depletion, but are subject to impairment testing. Provision for depreciation of other property is made primarily on a straight-line basis over the estimated useful life of the property. The annual rates of depreciation are as follows:

| | |
|---|---|
| Office and miscellaneous equipment: | 3-5 years |
| Leasehold improvements: | 8-12 years |

Foreign Exchange Transactions—For financial reporting purposes, the subsidiaries use the United States Dollar as their functional currency. Gains and losses on foreign currency transactions are included in income currently. The Company incurred gains on foreign currency transactions of $1.0 million, losses of $0.6 million and losses of $0.5 million in 2011, 2010 and 2009, respectively.

Accounts With Partners—Accounts with partners represent cash calls due or excess cash calls paid by the partners for exploration, development and production expenditures made by VAALCO Gabon (Etame), Inc. and VAALCO Angola (Kwanza), Inc.

Bad Debt—On a quarterly basis, the Company evaluates its accounts receivable balances to confirm collectability. Where collectability is in doubt, the Company records an allowance against the accounts receivable balance with a corresponding charge to net income as bad debt expense. Nearly all of the Company's accounts receivable balances are with its joint venture partners and purchasers of its oil, natural gas and natural gas liquids. Collection efforts, including remedies provided for in the contracts, are pursued to collect overdue amounts owed to the Company.

During 2011, the Company recorded a bad debt provision of $4.4 million related to the uncertainty in collecting its joint venture receivable in Angola.

Revenue Recognition—The Company recognizes revenues from crude oil and natural gas sales upon delivery to the buyer.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Stock Based Compensation—The Company measures the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award on the date of the grant. Grant date fair value is estimated using either an option-pricing model which is consistent with the terms of the award or a market observed price, if such a price exists. Such cost is recognized over the period during which an employee is required to provide service in exchange for the award (which is usually the vesting period). The Company estimates the number of instruments that will ultimately be issued, rather than accounting for forfeitures as they occur.

Fair Value of Financial Instruments—The Company's financial instruments consist primarily of cash, restricted cash, trade receivables and trade payables. The book values of cash, restricted cash, trade receivables, and trade payables are representative of their respective fair values due to the short-term maturity of these instruments.

Risks and Uncertainties—The Company's interests are located overseas in certain onshore and offshore areas in Gabon, offshore in Angola and the British North Sea and in Texas, Montana, Alabama, and the Louisiana Gulf Coast area.

Substantially all of the Company's crude oil and natural gas is sold at posted or index prices under short-term contracts, as is customary in the industry.

In Gabon, the Company sold crude oil under a contract with Mercuria Trading NV ("Mercuria"), which ran through calendar year 2011. For the 2012 calendar year, the Company will also sell its oil under a new contract with Mercuria. In 2010, Vitol S.A., and in 2009, Total Oil Trading S.A., were the crude oil buyers in Gabon and accounted for all of the Company's revenues in Gabon for those years. While the loss of the Company's buyer might have a material effect on the Company in the near term, management believes that the Company would be able to obtain other customers for its crude oil. Domestic operated production is sold under two contracts, one for oil and one for gas/liquids. The Company has access to several alternative buyers for oil and gas sales domestically.

Use of Estimates in Financial Statement Preparation—The preparation of financial statements in conformity with generally accepted accounting principles requires estimates and assumptions that affect the reported amounts of assets and liabilities as well as certain disclosures. The Company's financial statements include amounts that are based on management's best estimates and judgments. Actual results could differ from those estimates.

Estimates of oil and gas reserves used in the financial statements to estimate depletion expense and impairment charges require extensive judgments and are generally less precise than other estimates made in connection with financial disclosures. The Company considers its estimates to be reasonable; however, due to inherent uncertainties and the limited nature of data, estimates are imprecise and subject to change over time as additional information become available.

Subsequent Events—The Company has evaluated subsequent events through the date the financial statements were issued.

## 3. RECENT ACCOUNTING PRONOUNCEMENTS

Modernization of Oil and Gas Reporting—In December 2008, the SEC released Final Rule, *Modernization of Oil and Gas Reporting*, to revise the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances. The FASB aligned ASC Topic 932, *Extractive Industries – Oil and Gas*, with the SEC rules on this topic through the issuance of ASU 2010-13. Many of the

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The Company adopted these new rules and interpretations as of December 31, 2009.

## 4. STOCK BASED COMPENSATION

Stock options are granted under the Company's long-term incentive plan and have an exercise price that may not be less than the fair market value of the underlying shares on the date of grant. In general, stock options granted will become exercisable over a period determined by the Compensation Committee which in the past has been a five year life, with the options vesting over a three year period. A portion of the stock options granted in March 2011 and 2010 were vested immediately with the others vesting over a three year period. In addition, stock options will become exercisable upon a change in control, unless provided otherwise by the Compensation Committee. At December 31, 2011, there were 1,382,846 shares subject to options authorized but not granted.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized non-cash compensation expense of $2.2 million, $1.8 million and $1.8 million, respectively. These amounts were recorded as general and administrative expense. Because the Company does not pay significant United States taxes, no amounts were recorded for tax benefits.

A summary of the stock option activity for the year ended December 31, 2011 is provided below:

| | Number of Shares Underlying Options (in thousands) | Weighted Average Exercise Price Per Share | Weighted Average Remaining Contractual Term | Aggregate Intrinsic Value (in millions) |
|---|---|---|---|---|
| Outstanding at beginning of period | 4,266 | $ 5.40 | 2.64 | |
| Granted | 1,169 | $ 6.97 | 4.17 | |
| Exercised | (302) | $ 4.12 | 0.84 | |
| Forfeited | (1,328) | $ 7.95 | — | |
| Outstanding at end of period | 3,805 | $ 5.10 | 2.94 | $ 6.08 |
| Vested—end of period | 2,775 | $ 4.75 | 2.60 | $ 5.25 |
| Vested and expected to vest—end of period | 3,786 | $ 5.10 | 2.94 | $ 6.06 |

The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

As of December 31, 2011, unrecognized compensation costs totaled $0.9 million. The expense is expected to be recognized over a weighted average period of 1.1 years.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

A summary of the values of options granted and exercised for each of the years ending December 31, 2011, 2010 and 2009 is provided below:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Options granted—(thousands) | 1,169 | 1,565 | — |
| Weighted average grant date fair value—($/share) | $ 2.09 | $ 1.61 | — |
| Weighted average exercise price—($/share) | $ 4.12 | $ 4.28 | — |
| Options exercised (thousands) | 302 | 1,014 | 693 |
| Total intrinsic value of options exercised—($thousands) | $ 859 | $2,413 | $642 |

The Company received cash proceeds of $1.9 million, $0.5 million and $1.8 million from options exercised in 2011, 2010 and 2009, respectively.

During the year ended December 31, 2010, 672,300 options were exercised on a cashless basis, resulting in 120,695 shares being issued to employees and 551,605 shares being added to treasury stock.

The valuation of the options granted is based upon a Black Scholes model. The table below summarizes the assumptions used to value the options issued in 2011 and 2010. There were no options issued in 2009.

| Year | Options Issued (in thousands) | Weighted Avg. Volatility | Expected Term | Risk Free Interest Rate | Expected Dividend Yield |
|---|---|---|---|---|---|
| 2011 | 1,169 | 47% | 2.5 years | 0.8% | 0% |
| 2010 | 1,565 | 58% | 2.5 years | 2.6% | 0% |

The Company has no set policy for sourcing shares for options grants. Historically the shares issued under options grants have been new shares.

## 5. STOCKHOLDERS' EQUITY AND EARNINGS PER SHARE

The Company is authorized to issue up to 100 million shares of common stock. Basic earnings per share ("EPS") is calculated using the average number of shares of common stock outstanding during each period. Diluted EPS assumes the exercise of all stock options having exercise prices less than the average market price of the common stock using the treasury stock method. For purposes of computing EPS in a loss period, potential common shares are excluded from the computation of weighted average common shares outstanding as their effect is antidilutive. For the year ended December 31, 2009, 369,954 potential common shares were excluded. A reconciliation of diluted shares consists of the following:

| | Year Ended December 31, | | |
|---|---|---|---|
| Item | 2011 | 2010 | 2009 |
| Basic weighted average common stock issued and outstanding | 57,047,531 | 56,465,800 | 57,408,223 |
| Dilutive options | 925,050 | 572,253 | — |
| Total diluted shares | 57,972,581 | 57,038,053 | 57,408,223 |

A total of 1,169,064, 1,420,940, and 1,435,572, shares under option were not included because they were anti-dilutive during the years ended December 31, 2011, 2010 and 2009, respectively.

In the year ended December 31, 2011 and 2010, the Company did not repurchase any shares of the Company's common stock. Under previous share buyback programs, the Company acquired 2,327,779 shares in 2009.

**VAALCO ENERGY, INC AND SUBSIDIARIES**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

On September 14, 2007, the Board of Directors of the Company adopted a Rights Agreement dated as of September 14, 2007, between the Company and the Registrar and Transfer agent of the Company, as Rights Agent. Ratification of the rights plan required the affirmative vote of at least a majority vote of shares entitled to vote at the June 3, 2009 Annual Meeting. Stockholders did not approve the ratification. The Rights Agreement was redeemed at the rate of 1/10th of $0.01 per share and paid to stockholders at a cost to the Company of approximately $67,000 in 2009. In 2010, the Company received $5,000 for its share of the redemption held as treasury stock.

## 6. INCOME TAXES

The Company and its domestic subsidiaries file a consolidated United States income tax return. Certain subsidiaries' operations are also subject to foreign income taxes. Provision for income taxes consists of the following:

| *(In thousands)* | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| U.S. Federal: | | | |
| Current | $ — | $ — | $ — |
| Deferred | — | — | — |
| Foreign: | | | |
| Current | 93,468 | 35,260 | 36,902 |
| Deferred | — | — | — |
| Total | $93,468 | $35,260 | $36,902 |

The primary differences between the financial statement and tax bases of assets and liabilities at December 31, 2011 and 2010 are as follows: *(In thousands)*

| | 2011 | 2010 |
|---|---|---|
| Deferred Tax Assets: | | |
| Basis difference in fixed assets | $ 23,821 | $ 17,875 |
| Foreign tax credit carry forward | 57,825 | 37,950 |
| Alternative minimum tax credit carryover | 1,349 | 1,349 |
| Foreign net operating losses | 22,732 | 21,842 |
| Asset retirement obligations | 5,322 | 4,699 |
| Other | 1,566 | (209) |
| | $ 112,615 | $ 83,506 |
| Valuation allowance | (111,266) | (82,157) |
| Total deferred tax asset | $ 1,349 | $ 1,349 |

The Company's unused foreign tax credit will start to expire between the years 2013 and 2021. The alternative minimum tax credits do not expire, and foreign net operating losses ("NOL") are not subject to expiry dates. The NOL for the Company's UK subsidiary can be carried forward indefinitely, while the NOLs for the Company's Gabon and Angola subsidiaries are included in the respective subsidiaries' cost oil accounts, which will be offset against future taxable revenues.

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VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Pretax income (loss) is comprised of the following:

| *(In Thousands)* | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| United States | ($ 16,282) | ($ 4,129) | ($ 6,029) |
| Foreign | 150,312 | 81,776 | 38,787 |
| | $ 134,030 | $ 77,647 | $ 32,758 |

The statutory rate reconciliation is as follows:

| *(In Thousands)* | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| Pre-tax income multiplied by 35% | $46,911 | $27,176 | $11,465 |
| Foreign taxes not offset by U.S. foreign tax credits | 46,557 | 8,084 | 25,437 |
| Total income tax | $93,468 | $35,260 | $36,902 |

At December 31, 2011, the Company was subject to foreign and United States federal taxes only, with no allocations made to state and local taxes.

The following table summarizes the activity to the Company's unrecognized tax benefits:

| *(In Thousands)* | Year Ended December 31, 2011 | 2010 | 2009 |
|---|---|---|---|
| Balances at January 1, | $13,201 | $13,201 | $13,201 |
| Increases related to prior year positions | 0 | 0 | 0 |
| Balance at December 31, | $13,201 | $13,201 | $13,201 |

If recognized, none of the uncertain tax positions would impact the effective rate because they would be offset by valuation allowance.

Our accounting policy is to recognize interest and penalties accrued related to unrecognized tax benefits in income tax expense. The Company has no accruals for the payment of interest and penalties.

The following table summarizes the tax years that remain subject to examination by major tax jurisdictions:

| | |
|---|---|
| United States | 2006-2011 |
| Gabon | 2007-2011 |

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

## 7. COMMITMENTS AND CONTINGENCIES

### FPSO Charter

In October 2007, the Company entered into an amendment with the owner of the FPSO chartered for the Etame field to extend the contract until September 2015. In connection with the charter of the FPSO, the Company, as operator of the Etame field, guaranteed the charter payments through the same period. The charter continues for two years beyond that period unless one year's prior notice is given to the owner of the FPSO. The Company obtained several guarantees from its partners for their share of the charter payment. The Company's share of the charter payment is 28.1%. The Company believes the need for performance under the charter guarantee is remote. The estimated obligations for the annual charter payment and the Company's share of the charter payments through the end of the charter are as follows: *(in thousands)*

| Year | Full Charter Payment | Company Share |
|---|---|---|
| 2012 | $ 16,879 | $ 4,739 |
| 2013 | 16,833 | 4,726 |
| 2014 | 16,833 | 4,726 |
| 2015 | 11,621 | 3,263 |
| Total | $ 62,166 | $ 17,454 |

The Company has recorded a liability of $0.4 million at December 31, 2011 representing the guarantee's fair value.

The Company's share of charter expense, including a $0.25 per bbl charter fee for production up to 20,000 BOPD and a $2.50 per bbl charter fee for those bbls produced in excess of 20,000 BOPD, was $7.3 million, $7.8 million and $7.4 million for the years ending December 31, 2011, 2010 and 2009, respectively.

### Other Lease Obligations

In addition to the FPSO, the Company has operating lease obligations for rentals as follows: *(In thousands)*

| Year | Gross Obligation | Company Share |
|---|---|---|
| 2012 | $ 10,579 | $ 3,369 |
| 2013 | 4,166 | 1,500 |
| 2014 | 695 | 532 |
| 2015 | 433 | 433 |
| 2016 | 434 | 434 |
| Thereafter | 651 | 651 |
| Total | $ 16,958 | $ 6,919 |

The 2012 and 2013 lease obligation amounts are significantly higher than amounts for years beyond 2013 due to short term contracts for helicopter and marine vessels supporting the offshore Gabon operations.

The Company incurred rent expense of $3.6 million, $6.0 million and $5.3 million under operating leases for the years December 31, 2011, 2010 and 2009, respectively.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

**Gabon Obligation**

Under the terms of the Etame Production Sharing Contract, the consortium is required to provide to the local government refinery a volume of crude at a 25% discount to market price (the “Gabon Obligation”). The volume required to be furnished is the amount of the Etame Marin block production divided by the total Gabon production times the volume of oil refined by the refinery per year. In 2011, the Company paid $2.8 million for its share of the 2010 obligation. In 2010, the Company paid $1.3 million for its share of the 2009 obligation. In 2009, the Company paid $2.8 million for its share of the 2008 obligation. The Company accrues an amount for the Gabon Obligation based on management’s best estimate of the volume of crude required, because the refinery does not publish its throughput figures. The amount accrued at December 31, 2011, for the Company’s share of the 2011 obligation is $4.0 million.

**Offshore Gabon**

In addition to the contractual obligations described above, the Company entered into a sixth exploration period extension during 2009 and is required to spend $5.3 million for its share of two exploration wells and to acquire and process 150 square kilometers of 3-D seismic on the Etame Marin block by July 2014. One of the two exploration commitment wells was drilled in 2010 on the Omangou prospect at a cost of $8.6 million ($2.6 million net to the Company). The seismic obligation was met with the acquisition of 223 square kilometers of 3-D seismic in 2011. The remaining obligation is the drilling of one exploration well.

As part of securing the second ten year production license with the government of Gabon, the Company agreed in principle to a cash funding arrangement for the eventual abandonment of the offshore wells, platforms and facilities. The agreement is not yet signed, but calls for annual funding for the next seven years at 12.14% of the total abandonment estimate per year and 5.0% per year for the last three years of the production license. The amounts paid will be reimbursed through the cost account and are non-refundable to the Company. The funding is expected to begin in 2012 after the agreement is finalized. The abandonment estimate for this purpose is estimated to be approximately $14.0 million net to the Company on an undiscounted basis. As in prior periods, the obligation for abandonment of the Gabon offshore facilities is included in the asset retirement obligation shown on the Company’s balance sheet.

**Onshore Gabon**

In November 2005, the Company signed a production sharing contract for the Mutamba Iroru block onshore Gabon. The five year contract awarded the Company exploration rights to approximately 270,000 acres along the central coast of Gabon. The Mutamba Iroru block was previously held by Shell Gabon. The Company acquired aeromagnetic gravity data in 2008, and together with seismic data acquired from previous operators over the block in 2006 and 2007, drilled two exploration wells in 2009. Both wells encountered water bearing sands and were abandoned.

In 2010, in conjunction with executing a farm-out agreement with Total Gabon, the exploration period was extended until May 2012. This extension requires the Company to reprocess 400 kilometers of 2-D seismic data and drill one exploration well. In return for Total Gabon funding an agreed portion of the new work commitment, Total Gabon will receive a 50% interest on the permit. The seismic reprocessing began in the first quarter of 2011 and was largely completed by the end of 2011. The Company expects to request an extension period in the first quarter of 2012 as the rig to drill the exploration well is not expected to be available until the third quarter of 2012. However, the Company can provide no assurances that such a request will be granted.

**Angola**

In November 2006, the Company signed a production sharing contract for Block 5 offshore Angola. The four year primary term with an optional three year extension awards the Company exploration rights to 1.4 million acres offshore central Angola. The Company's working interest is 40%. Additionally, the Company is required to carry the Angolan national oil company, Sonangol P&P, for 10% of the work program. During the first four years of the contract the Company was required to acquire and process 1,000 square kilometers of 3-D seismic, drill two exploration wells and expend a minimum of $29.5 million ($14.8 million net to the Company). The Company fulfilled its seismic obligation when it acquired 1,175 square kilometers of 3-D seismic data at a cost of $7.5 million ($3.75 million net to the Company) in January 2007 and 524 square kilometers of 3-D seismic data during the fourth quarter of 2008 at a cost of $6.0 million ($3.0 million net to the Company).

The government-assigned working interest partner was delinquent paying their share of the costs several times in 2009 and consequently was placed in a default position. By a governmental decree dated December 1, 2010, the former partner was removed from the production sharing contract, and a one year time extension was granted for drilling the two exploration commitment wells. Following the decree, the Company and the government of Angola have been working together to obtain a replacement partner. Options to amend the two-well commitment are also being discussed with the Angolan government. Because of the uncertainty surrounding the outcome of the discussions with the Angolan government, the Company recorded a full allowance of $4.4 million against the accounts receivable from partners for the amounts owed to the Company above its 40% working interest plus the 10% carried interest. In early 2012, the Angolan government granted a further one year extension for drilling the two exploration commitment wells in accordance with the production sharing contract.

Due to the timing uncertainty of obtaining a replacement partner and the outcome of discussions regarding modifying the drilling well commitments required by the production sharing contract, a time extension may be necessary beyond the current expiration date of November 30, 2012. If the government of Angola were to deny a request for a further time extension, the Company may be required to impair its leasehold costs and other investments totaling $11.0 million as of December 31, 2011. The Company may also be required to pay the Angolan government $10.0 million in lieu of drilling the two exploration commitment wells.

**United States**

In September 2011, the Company acquired a 65% working interest in approximately 22,000 gross acres (14,300 net acres) covering the Middle Bakken and deeper formations in the East Poplar unit and the Northwest Poplar field in Roosevelt County, Montana. Pursuant to the terms of the acquisition, the Company is required to drill three wells at its sole cost, one of which must be drilled by June 1, 2012 and the remaining two wells must be drilled by the end of 2012. A vertical exploration well, which met the time requirement for drilling the first well, was spudded in December 2011 to evaluate the formations. The Company expects to drill two additional wells on this property in 2012 in accordance with the terms of the agreement.

## 8. TERMINATION OF IFC CREDIT FACILITY

In June 2005, the Company executed a loan agreement with the International Finance Corporation ("IFC") for a $30.0 million revolving credit facility secured by the assets of the Company's Gabon subsidiary.

The facility extended until October 2009 at which point it could be extended by mutual agreement, and the loan drawdown amount could be converted to a term loan at the Company's option. Because of the Company's limited use of the facility, the IFC elected to not extend an offer to extend the unused capacity in the credit facility. The Company elected to not convert the loan balance to a term loan and instead repaid the loan balance of $5.0 million plus interest in mid-October 2009.

## 9. PARTNER REALIGNMENT AGREEMENT

On June 3, 2009, a realignment agreement was signed with a joint venture partner that originally did not participate in an appraisal well and one of the development wells in the Ebouri field, offshore Gabon. Pursuant to the realignment agreement, the joint venture partner paid its proportionate share of capital expenditures for the wells, which reduced the Company's capital expenditures by $5.7 million. In addition, the Company benefited from a $15.0 million ($6.5 million net to the Company) risk premium being paid by the partner benefiting the other joint venture partners that originally participated in those two wells which the Company received and recognized as other operating income in 2009.

## 10. CAPITALIZATION OF EXPLORATORY WELL COSTS

ASC Topic 932—*Extractive Industries* provides that an exploratory well shall be capitalized as part of the entity's uncompleted wells pending the determination of whether the well has found proved reserves. Further, an exploration well that discovers oil and gas reserves, but those reserves cannot be classified as proved when drilling is completed, shall be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either condition is not met, the exploration well would be assumed to be impaired and its costs would be charged to expense.

In the second and third quarters of 2010, the Company drilled the Southeast Etame No. 1 well with two sidetracks in the Etame Marin block offshore Gabon. The well discovered a five meter sand of oil. Additional evaluation of the well and sidetrack information was conducted to facilitate options for developing the discovery. During 2011 and continuing into 2012, the Company and its joint venture partners continue to evaluate the merits of two development options which will lead to a single recommendation for the Company and the venture partners to approve. One option involves a sub-sea well to develop the Southeast Etame discovery only, whereas the second option envisions a platform development to access both the Southeast Etame area as well as the North Tchibala field, where a discovery was made on the block prior to VAALCO's block participation. The Company believes a decision on the development plan for the Southeast Etame area will be made in 2012. The Company has capitalized $8.0 million for this well in accordance with the criteria contained in ASC Topic 932.

## 11. EMPLOYEE BENEFIT PLANS

The Company sponsored a 401(k) plan, without a Company match feature, for its employees through the end of 2009. A replacement 401(k) plan was put in place in January 2010 which has a Company matching component. Costs incurred in 2011 and 2010 for administering the plan, including the match feature, were approximately $172,000 and $150,000, respectively. Costs incurred in 2009 for administering and ceasing the former 401(k) plan at December 31, 2009 were $151,000.

The Company also has a retirement and severance policy for its employees. The benefit is a one-time payment based on receiving one month's pay at current pay rates for each year of employment. A liability has been recorded for this policy in the amount of $2.3 million and $2.0 million as of December 31, 2011 and 2010, respectively. No payments to retiring employees were made in 2011 or 2010. Payments totaled $277,000 in 2009.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

## 12. ASSET RETIREMENT OBLIGATIONS

The fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred by capitalizing it as part of the carrying amount of the long-lived assets. The Company records asset retirement obligations for the future abandonment costs of tangible assets such as platforms, wells, pipelines and other facilities. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

A summary of the recording of the estimated fair value of the Company's asset retirement obligations is presented as follows:

| *(In Thousands)* | Year Ended December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Balances at January 1, | $13,425 | $10,666 | $10,071 |
| Accretion Expense | 1,014 | 825 | 811 |
| Additions | 96 | 2,016 | 720 |
| Revisions | (7) | (82) | (936) |
| Balance December 31, | $14,528 | $13,425 | $10,666 |

During the year ended December 31, 2011, the Company increased the asset retirement obligations to recognize the abandonment liability for the new well in the Granite Wash formation in North Texas. During the year ended December 31, 2010, the Company increased the asset retirement obligations to recognize the abandonment liability for three new development wells (Ebouri 4-H, Etame 7-H, and S. Tchibala 2-H). The increase in the asset retirement obligation liabilities during the year ended December 31, 2009 was due to an additional well on the Ebouri platform.

As of December 31, 2011, the Company had $44,000 legally restricted for settling asset retirement obligations in the United States.

The Company does not plan to abandon any material assets over the next five years.

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## 13. SEGMENT INFORMATION

The Company's operations are based in Gabon, Angola, the British North Sea and in the United States. Management reviews and evaluates the operation of each geographic segment separately. The operations of all segments include exploration for and production of hydrocarbons where commercial reserves have been found and developed. The accounting policies of the reportable segments are the same as in Note 2. Revenues are based on the location of hydrocarbon production. The Company evaluates each segment based on income (loss) from operations. Segment activity for the years ended December 31, 2011, 2010 and 2009 are as follows: *(in thousands)*

| 2011 | Gabon | Angola | North Sea | USA | Corporate and Other | Total |
|---|---|---|---|---|---|---|
| Revenues | $208,781 | $ — | $ — | 1,655 | — | $210,436 |
| Depreciation, depletion and amortization | 23,604 | 20 | — | 1,922 | 50 | 25,596 |
| Operating income (loss) | 155,550 | (6,221) | (382) | (7,680) | (8,706) | 132,561 |
| Interest income | 80 | — | — | — | 104 | 184 |
| Income taxes | 93,468 | — | — | — | — | 93,468 |
| Provision for bad debt | — | 4,448 | — | — | — | 4,448 |
| Impairment of long lived assets | — | — | — | 4,975 | — | 4,975 |
| Additions to properties and equipment | 8,528 | 7 | — | 24,371 | 60 | 32,966 |
| Long lived assets | 68,965 | 10,964 | — | 19,772 | 147 | 99,848 |
| Total assets | 185,341 | 21,452 | — | 22,236 | 45,986 | 275,015 |

| 2010 | Gabon | Angola | North Sea | USA | Corporate and Other | Total |
|---|---|---|---|---|---|---|
| Revenues | $134,346 | $ — | $ — | 126 | $ — | $134,472 |
| Depreciation, depletion and amortization | 19,946 | 16 | — | 11 | 48 | 20,021 |
| Operating income (loss) | 85,594 | (2,846) | (425) | (387) | (3,813) | 78,123 |
| Interest income | 85 | — | — | — | 66 | 151 |
| Income taxes | 35,260 | — | — | — | — | 35,260 |
| Additions to properties and equipment | 38,082 | 27 | — | 2,260 | 83 | 40,452 |
| Long lived assets | 83,412 | 10,977 | — | 2,295 | 136 | 96,820 |
| Total assets | 181,642 | 14,081 | — | 3,189 | 39,488 | 238,400 |

| 2009 | Gabon | Angola | North Sea | USA | Corporate and Other | Total |
|---|---|---|---|---|---|---|
| Revenues | $115,214 | $ — | $ — | 84 | $ — | $115,298 |
| Depreciation, depletion and amortization | 20,702 | 14 | — | 1 | 43 | 20,760 |
| Operating income (loss) | 52,625 | (3,218) | (9,819) | (28) | (6,541) | 33,019 |
| Interest income | 91 | 36 | — | — | 527 | 654 |
| Interest expense | 450 | — | — | — | — | 450 |
| Income taxes | 36,902 | — | — | — | — | 36,902 |
| Additions to (disposal of) properties and equipment | 13,280 | 1 | (794) | — | (328) | 12,159 |

## 14. IMPAIRMENT OF PROVED PROPERTIES

During the year ended December 31, 2011 the Company recognized an impairment loss in its United States segment for $5.0 million to write down the value of its first Granite Wash formation well to its estimated fair value of $4.2 million. Mechanical problems with the well have impacted the estimation of recoverable reserves from the well and an impairment was warranted.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The initial measurement of these assets at fair value is calculated using discounted cash flow techniques and based on estimates of future revenues and costs associated with the Granite Wash formation well. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of future crude oil and natural gas prices, production costs, development expenditures, and anticipated production of proved and probable reserves, appropriate risk-adjusted discount rates and other relevant data. For crude oil, estimates were based on NYMEX West Texas Intermediate prices, adjusted for quality, transportation fees, and a regional price differential. For natural gas, estimates were based on NYMEX Henry Hub prices, adjusted for energy content, transportation fees, and a regional price differential.

## 15. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following represents our unaudited quarterly results for years ended December 31, 2011 and 2010. The quarterly results were prepared in accordance with generally accepted accounting principles and reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. These adjustments are of a normal recurring nature.

| *(In thousands of dollars except per share information)* | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| **2011** | | | | |
| Total revenues[1] | $46,772 | $58,547 | $37,350 | $67,767 |
| Total operating costs and expenses | 15,430 | 16,035 | 17,531 | 28,879 |
| Operating income | 31,342 | 42,512 | 19,819 | 38,888 |
| Net income | 12,896 | 13,510 | 3,455 | 10,701 |
| Net income attributable to noncontrolling interest | (1,657) | (1,723) | (1,056) | (1,981) |
| Net income attributable to VAALCO Energy, Inc. | 11,239 | 11,787 | 2,399 | 8,720 |
| Basic net income per share attributable to VAALCO Energy, Inc.[2] | $ 0.20 | $ 0.21 | $ 0.04 | $ 0.15 |
| Diluted net income per share attributable to VAALCO Energy, Inc.[2] | $ 0.19 | $ 0.20 | $ 0.04 | $ 0.15 |

| *(In thousands of dollars except per share information)* | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| **2010** | | | | |
| Total revenues | $30,006 | $33,675 | $32,604 | $38,187 |
| Total operating costs and expenses | 12,127 | 13,582 | 11,001 | 19,639 |
| Operating income | 17,879 | 20,093 | 21,603 | 18,548 |
| Net income | 6,924 | 11,414 | 13,933 | 10,116 |
| Net income attributable to noncontrolling interest | (956) | (1,378) | (1,482) | (1,231) |
| Net income attributable to VAALCO Energy, Inc. | 5,968 | 10,036 | 12,451 | 8,885 |
| Basic net income per share attributable to VAALCO Energy, Inc.[2] | $ 0.11 | $ 0.18 | $ 0.22 | $ 0.16 |
| Diluted net income per share attributable to VAALCO Energy, Inc.[2] | $ 0.11 | $ 0.18 | $ 0.22 | $ 0.15 |

(1) The number of oil liftings conducted offshore Gabon were 3, 3, 2, and 4 for the 1st quarter, the 2nd quarter, the 3rd quarter, and the 4th quarter, respectively.

(2) Quarterly income per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters due to the exercise of stock options and issuance of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

## 16. SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following information is being provided as supplemental information in accordance with certain provisions of ASC Topic 932—*Extractive Activities- Oil and Gas*. The Company's reserves are located offshore of Gabon and in Texas. The following tables set forth costs incurred, capitalized costs, and results of operations relating to oil and natural gas producing activities for each of the periods. (See Footnote 1—"ORGANIZATION")

**Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities**

| *(In thousands)* | United States | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Costs incurred during the year: | | | |
| Exploration—capitalized | $ — | — | $ — |
| Exploration—expensed | 2,083 | 392 | 47 |
| Acquisition | 9,495 | 2,240 | — |
| Development | 14,936 | — | — |
| Total | $26,514 | 2,632 | $ 47 |

| *(In thousands)* | International | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Costs incurred during the year: | | | |
| Exploration—capitalized | $ 69 | $ 8,020 | $ 2,257 |
| Exploration—expensed | 3,625 | 6,421 | 36,417 |
| Acquisition | 455 | 1,200 | — |
| Development | 8,011 | 29,927 | 12,143 |
| Total | $12,160 | $ 45,568 | $50,817 |

Exploration expense includes $0.1 million, $2.6 million and $33.4 million for dry hole expense in 2011, 2010 and 2009, respectively.

**Capitalized Costs Relating to Oil and Gas Producing Activities:**

| | December 31, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| Capitalized costs— Properties not being amortized | $ 46,047 | $ 25,504 | $ 15,036 |
| Properties being amortized(1) | 182,820 | 170,457 | 140,555 |
| Total capitalized costs | $ 228,867 | $195,961 | $155,591 |
| Less accumulated depreciation, depletion, and amortization | (129,166) | (99,277) | (80,127) |
| Net capitalized costs | $ 99,701 | $ 96,684 | $ 75,464 |

(1) Includes $10.4 million, $10.3 million, and $8.4 million asset retirement cost in 2011, 2010, and 2009, respectively.

VAALCO ENERGY, INC AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The capitalized costs pertain to the Company's producing activities in Gabon, leasehold acreage in Gabon and Angola, and U.S. activities.

**Results of Operations for Oil and Gas Producing Activities:**

| | United States | | | International | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 Gabon | 2010 Gabon | 2009 Gabon |
| Crude oil and gas sales | $ 1,655 | $ 126 | $ 84 | $ 208,781 | $ 134,346 | $ 115,214 |
| Production, G&A and other expense | (7,413) | (495) | (103) | (27,471) | (28,614) | (20,506) |
| Depreciation, depletion and amortization | (1,922) | (11) | (11) | (23,604) | (19,946) | (20,321) |
| Income tax | — | (7) | (8) | (93,468) | (35,260) | (36,902) |
| Results from oil and gas producing activities | $ (7,680) | $ (387) | $ (38) | $ 64,238 | $ 50,526 | $ 37,485 |

**Proved Reserves**

Reserve reports as of December 31, 2011, 2010, and 2009 have been prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers. The following tables set forth the net proved reserves of the Company as of December 31, 2011, 2010 and 2009, and the changes during such periods.

| | Oil (MBbls) | Gas (MMCF) |
|---|---|---|
| PROVED RESERVES: | | |
| BALANCE AT JANUARY 1, 2009 | 7,422 | 30 |
| Production | (1,936) | (6) |
| Revisions of previous estimates | 783 | (1) |
| Extensions and discoveries | 1,094 | — |
| BALANCE AT DECEMBER 31, 2009 | 7,363 | 23 |
| Production | (1,715) | (38) |
| Revisions of previous estimates | 1,274 | 38 |
| Extensions and discoveries | — | — |
| BALANCE AT DECEMBER 31, 2010 | 6,922 | 23 |
| Production | (1,868) | (255) |
| Revisions of previous estimates | 959 | 31 |
| Extensions and discoveries | 35 | 2,126 |
| BALANCE AT DECEMBER 31, 2011 | 6,048 | 1,925 |

| | Oil (MBbls) | Gas (MMCF) |
|---|---|---|
| PROVED DEVELOPED RESERVES | | |
| Balance at January 1, 2009 | 4,751 | 30 |
| Balance at December 31, 2009 | 4,795 | 23 |
| Balance at December 31, 2010 | 5,029 | 23 |
| Balance at December 31, 2011 | 3,854 | 856 |

The Company's proved developed reserves are located offshore Gabon and in Texas. The reserves in Gabon include the minority interest share of reserves held by the 9.99% owner of VAALCO International, Inc., which owns VAALCO Gabon (Etame), Inc.

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Revisions in 2009 were attributable to better reservoir performance at the Etame field. Extensions and discoveries in 2009 were the result of successful drilling of step out wells at the Ebouri field that increased the amount of proven acreage for the field. Revisions in 2010 were primarily associated with better reservoir performance in several of the Etame Marin block fields. Revisions in 2011 were attributable to better reservoir performance at the Etame, Avouma, South Tchibala and Ebouri fields. In 2011, discoveries were attributable to the Granite Wash formation leases in North Texas.

The Company maintains a policy of not booking proved reserves on discoveries until such time as a development plan has been prepared for the discovery. Additionally, the development plan is required to have the approval of the Company's partners in the discovery. Furthermore, if a government agreement that the reserves are commercial is required to develop the field, this approval must have been received prior to booking any reserves.

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

The information that follows has been developed pursuant to procedures prescribed by ASC Topic 932 and utilizes reserve and production data estimated by independent petroleum consultants. The information may be useful for certain comparison purposes, but should not be solely relied upon in evaluating VAALCO Energy, Inc. or its performance.

In accordance with the guidelines of the SEC, the Company's estimates of future net cash flow from the Company's properties and the present value thereof are made using oil and gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The future cash flows are also based on costs in existence at the dates of the projections, excluding Gabon royalties, and the interests of other consortium members. Future production costs do not include overhead charges allowed under joint operating agreements or headquarters general and administrative overhead expenses. Future development costs include $22.5 million attributable to future abandonment when the wells become uneconomic to produce.

| *(In thousands)* | United States | | | International | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | December 31, | | | December 31, | | | December 31, | | |
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| Future cash inflows | $13,274 | $ 407 | $ 316 | $ 623,546 | $ 517,051 | $ 394,500 | $ 636,820 | $ 517,458 | $ 394,816 |
| Future production costs | (1,661) | (203) | (179) | (154,020) | (140,470) | (84,154) | (155,681) | (140,673) | (84,333) |
| Future development costs | (4,180) | — | — | (85,528) | (71,190) | (59,054) | (89,708) | (71,190) | (59,054) |
| Future income tax expense | (1,347) | (34) | (27) | (181,886) | (159,811) | (130,732) | (183,233) | (159,845) | (130,759) |
| Future net cash flows | $ 6,086 | $ 170 | $ 110 | $ 202,112 | $ 145,580 | $ 120,560 | $ 208,198 | $ 145,750 | $ 120,670 |
| Discount to present value at 10% annual rate | (3,150) | (41) | (19) | (38,861) | (20,885) | (18,132) | (42,011) | (20,926) | (18,151) |
| Standardized measure of discounted future net cash flows | $ 2,936 | $ 129 | $ 90 | $ 163,251 | $ 124,695 | $ 102,428 | $ 166,187 | $ 124,824 | $ 102,518 |

International income taxes represent amounts payable to the Government of Gabon on profit oil as final payment of corporate income taxes, and domestic income taxes represent amounts payable for severance taxes in Texas.

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**Changes in Standardized Measure of Discounted Future Net Cash Flows:**

The following table sets forth the changes in standardized measure of discounted future net cash flows as follows:

| *(In thousands)* | December 31, 2011 | December 31, 2010 | December 31, 2009 |
|---|---|---|---|
| BALANCE AT BEGINNING OF PERIOD | $ 124,824 | $ 102,518 | $ 64,953 |
| Sales of oil and gas, net of production costs | (183,705) | (112,360) | (93,321) |
| Net changes in prices and production costs | 194,633 | 139,810 | 148,174 |
| Revisions of previous quantity estimates | 75,713 | 71,600 | 30,178 |
| Additions | 7,742 | — | 42,106 |
| Changes in estimated future development costs | (5,831) | (5,337) | (21,969) |
| Development costs incurred during the period | 31,913 | 37,531 | 22,229 |
| Accretion of discount | 12,482 | 10,252 | 6,495 |
| Net change of income taxes | 4,455 | (31,482) | (66,702) |
| Change in production rates (timing) and other | (96,039) | (87,708) | (29,625) |
| BALANCE AT END OF PERIOD | $ 166,187 | $ 124,824 | $102,518 |

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of the Company. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. The standardized measure of discounted future net cash flow should not be construed as the current market value of the estimated oil and natural gas reserves attributable to the Company’s properties. The information set forth in the foregoing tables includes revisions for certain reserve estimates attributable to proved properties included in the preceding year’s estimates. Such revisions are the result of additional information from subsequent completions and production history from the properties involved or the result of a decrease (or increase) in the projected economic life of such properties resulting from changes in product prices. Moreover, crude oil amounts shown for Gabon are recoverable under a service contract and the reserves in place remain the property of the Gabon government.

In accordance with the guidelines of the Securities and Exchange Commission, the Company’s estimates of future net cash flow from the Company’s properties and the present value thereof are made using oil and gas contract prices using a twelve month average of beginning of month prices and are held constant throughout the life of the properties except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. In Gabon, the price was $110.08 per bbl. In the United States, the price was $78.89 per bbl of oil and $5.439 per Mcf of gas.

Under the Production Sharing Contract in Gabon, the Gabonese government is the owner of all oil and gas mineral rights. The right to produce the oil and gas is stewarded by the Directorate Generale de Hydrocarbures and the Production Sharing Contract was awarded by a decree from the State. Pursuant to the service contract, the Gabon government receives a variable royalty depending on production rate.

The consortium maintains a Cost Account, which entitles it to receive 70% of the production remaining after deducting the royalty so long as there are amounts remaining in the Cost Account. At December 31, 2011,

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there was $3.8 million in the cost account net to the Company. As payment of corporate income taxes the consortium pays the government an allocation of the remaining “profit oil” production from the contract area ranging from 50% to 60% of the oil remaining after deducting the royalty and the cost oil. The percentage of “profit oil” paid to the government as tax is a function of production rates. So long as amounts remain in the Cost Account, the net share that the consortium receives from production can range from a low of 67.7% of production at production rate in excess of 25,000 BOPD to a high of 82.5% of production at rates below 5,000 BOPD. However, when the Cost Account becomes substantially recovered, the Company only recovers ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. The Cost Account has been substantially recovered since the first quarter of 2005. In 2009, the Company cost recovered 812,000 barrels out of a theoretical 1,391,000 barrels which would have been recoverable if the Cost Account was full. In 2010, the Company cost recovered 838,000 barrels out of a theoretical 1,200,000 barrels which would have been recoverable if the Cost Account was full. In 2011, the Company cost recovered 304,000 barrels out of a theoretical 1,303,000 barrels which would have been recoverable if the Cost Account was full.

Also because of the nature of the Cost Account, increases in oil prices result in a lesser number of barrels required to recover costs, therefore at higher oil prices, the Company’s net reserves after taxes would decrease, but at lower prices the Company’s Cost Oil barrels increase.

The Etame Production Sharing Contract allows for the carve-out of a development area, which was performed for the Etame, Avouma and Ebouri fields. The Etame development area has a term of 20 years and will expire in 2021. The Avouma field development area has a term of 20 years and will expire in 2025. The Ebouri field development area has a term of 20 years and will expire in 2026. The balance of the Etame Marin block comprises the exploration area, which expires in July 2014.

Under the service contract, it is not anticipated that the Gabonese government will take physical delivery of its allocated production. Instead, the Company is authorized to sell the Gabonese government’s share of production and remit the proceeds to the Gabonese government.

The Mutamba Iroru production sharing contract entitles the Company to receive 70% of any future production remaining after deducting the royalty so long as there are amounts remaining in the Cost Account. At December 31, 2011 there was $28.2 million in the Cost Account. As payment of corporate income taxes the consortium pays the government an allocation of the remaining “profit oil” production from the contract area ranging from 50% to 63% of the oil remaining after deducting the royalty and the cost oil. The percentage of “profit oil” paid to the government as tax is a function of production rates. So long as amounts remain in the Cost Account, the net share that the consortium receives from production can range from a low of 72% of production at production rate in excess of 20,000 BOPD to a high of 85% of production at rates below 7,500 bbl per day. However, when the Cost Account becomes substantially recovered, the Company only recovers ongoing operating expenses and new project capital expenditures, resulting in a higher tax rate. The Mutamba Iroru service contract provides for all commercial discoveries to be reclassified into a development area with a term of twenty years. At December 31, 2011, the Company has no proved reserves related to the Mutamba Iroru block.

The Block 5 production sharing contract in Angola entitles the Company to receive 50% of the any future production so long as there are amounts remaining in the Cost Account. There are no royalty payments under the contract. The consortium pays the government an allocation of the remaining “profit oil” production from the contract area ranging from 30% to 90% of the oil remaining after deducting the cost oil. The percentage of “profit oil” paid to the government as tax is a function of the Company’s rate of return for each development area. The Block 5 production sharing contract provides for a discovery to be reclassified into a development area with a term of twenty years. At December 31, 2011, the Company has no proved reserves related to Block 5 in Angola.

**Exhibit 21.1**

| Subsidiary Name | Business | Ownership | Date and State of Incorporation | |
|---|---|---|---|---|
| VAALCO Energy (USA), Inc. | Energy | 100% | 10/16/96 | Delaware |
| VAALCO International, Inc | Energy | 90.01% | 7/31/02 | Delaware |
| VAALCO Gabon (Etame), Inc. | Energy | 90.01% | 6/14/95 | Delaware |
| VAALCO Production (Gabon), Inc. | Energy | 100% | 6/14/95 | Delaware |
| VAALCO Angola (Kwanza), Inc. | Energy | 100% | 5/15/06 | Delaware |
| VAALCO UK (North Sea), Limited | Energy | 100% | 5/22/06 | England |

**Exhibit 23.1**

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-67858, 333-102649, 333-103576, 333-114448, and 333-144849 on Form S-8 and Registration Statement Nos. 333-59095 and 333-121549 on Form S-3 of our reports dated March 12, 2012, relating to the consolidated financial statements of VAALCO Energy, Inc. and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of new accounting guidance in 2009 related to the estimation of oil and gas reserves), and the effectiveness of VAALCO Energy, Inc.'s internal control over financial reporting, appearing in this Annual Report on Form 10-K of VAALCO Energy, Inc. for the year ended December 31, 2011.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 12, 2012

**Exhibit 23.2**

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

As oil and gas consultants, we hereby consent to the incorporation by reference in current and future effective Registration Statements on Form S-3 and Form S-8 of our reports dated January 31, 2012 and February 2, 2012 included in VAALCO Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011, and to the reference to us under the caption "Experts" appearing in such Registration Statement.

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: /s/ Danny D. Simmons
Danny D. Simmons, P.E.
President and Chief Operating Officer

Houston, Texas
March 12, 2012

**Exhibit 31.1**

*I, Robert L. Gerry, III, certify that:*

*(1) I have reviewed this annual report on Form 10-K of VAALCO Energy, Inc.;*

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

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

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

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

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

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

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

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

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

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

*Date March 12, 2012*

*/s/ Robert L. Gerry, III*
*Robert L. Gerry, III*
*Chief Executive Officer*

**Exhibit 31.2**

*I, Gregory R. Hullinger, certify that:*

*(1) I have reviewed this annual report on Form 10-K of VAALCO Energy, Inc.;*

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

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

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

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

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

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

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

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

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

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

*Date March 12, 2012*

/s/ *Gregory R. Hullinger*
*Gregory R. Hullinger*
*Chief Financial Officer*

EXHIBIT 32.1

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

In connection with the Annual Report of VAALCO Energy, Inc. (the "**Company**") on Form 10-K for the year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "**Report**"), I, Robert L. Gerry, III, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

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

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

Dated: March 12, 2012

/s/ Robert L. Gerry, III
Robert L. Gerry, III, Chief Executive Officer

**EXHIBIT 32.2**

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

In connection with the Annual Report of VAALCO Energy, Inc. (the '**Company**") on Form 10-K for the annual period ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "**Report**"), I, Gregory R. Hullinger, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

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

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

Dated: March 12, 2012

/s/Gregory R. Hullinger
Gregory R. Hullinger, Chief Financial Officer

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

EXECUTIVE COMMITTEE
P. SCOTT FROST - DALLAS
J. CARTER HENSON, JR. - HOUSTON
DAN PAUL SMITH - DALLAS
JOSEPH J. SPELLMAN - DALLAS
THOMAS J. TELLA II - DALLAS

January 31, 2012

Mr. W. Russell Scheirman, II
VAALCO Gabon (Etame), Inc.
4600 Post Oak Place, Suite 309
Houston, Texas 77027
Dear Mr. Scheirman:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the VAALCO Gabon (Etame), Inc. (referred to herein as "VAALCO") interest in certain oil properties located in Avouma/South Tchibala, Ebouri, and Etame Fields, offshore Gabon. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 94 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO Energy, Inc.'s use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the oil reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2011, to be:

| | Oil Reserves | | Future Net Revenue (M$) | |
|---|---|---|---|---|
| Category | Gross (MBBL) | Net[1] (MBBL) | Total | Present Worth at 10% |
| Proved Developed Producing | 15,701.1 | 3,834.9 | 144,401.7 | 125,935.1 |
| Proved Undeveloped | 8,913.1 | 2,177.0 | 57,711.1 | 37,316.0 |
| Total Proved | 24,614.2 | 6,011.8 | 202,112.8 | 163,251.2 |

*Totals may not add because of rounding.*

(1) Net reserves are prior to deductions for "income tax barrels".

The oil reserves shown include crude oil only. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Produced gas is flared or consumed in field operations. Monetary values shown in this report are expressed in United States dollars ($) or thousands of United States dollars (M$).

The estimates shown in this report are for proved developed producing and proved undeveloped reserves. Our study indicates that there are no proved developed non-producing reserves for these properties at this time. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

The contractors' share of production is calculated pursuant to the provisions of the production sharing contract for the Etame Marine permit that includes Avouma/South Tchibala, Ebouri, and Etame Fields. Included are determinations of cost oil incorporating the unrecovered cost pool, as of December 31, 2011, and estimated cost-recoverable items scheduled to be purchased in the future. Also included are determinations of profit oil based on estimated future oil producing rates.

As requested, our estimates of net reserves are prior to deductions for the portion of the government's share of the profit oil required for payment of VAALCO's Gabon income taxes, referred to as "income tax barrels". These income tax volumes have been calculated as the government's share of profit oil multiplied by VAALCO's working interest, net of government participation.

Gross revenue shown in this report is VAALCO's share of the gross (100 percent) revenue from the properties prior to deducting all production sharing revenue paid to the Gabon government. Future net revenue is after deductions for this amount, capital costs, operating expenses, production taxes, and abandonment costs and credits for state reimbursement but before consideration of any United States income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

The oil price used in this report is based on the 12-month unweighted arithmetic average of the first-day-of-the-month U.S. Energy Information Administration Europe Brent spot price for each month in the period January through December 2011. The average price of $111.02 per barrel is adjusted for quality, transportation fees, and a regional price differential. The adjusted oil price of $110.08 is held constant throughout the lives of the properties.

Operating costs used in this report are based on operating expense records of VAALCO, the operator of the properties. These costs include the overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred offshore Gabon. Headquarters general and administrative overhead expenses of VAALCO are included to the extent that they are covered under joint operating agreements. Operating costs are held constant through December 31, 2016, which is the termination date of the floating production, storage, and offloading (FPSO) vessel contract plus one of the two one-year extensions permitted under this contract. These costs are then increased to reflect our estimate of the current market cost for FPSO vessels and held constant throughout the remaining lives of the properties.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of VAALCO's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, platforms, and production facilities; these estimates do not include any salvage value for the platform and well equipment. Capital costs and abandonment costs are held constant to the date of expenditure.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, other interest owners, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The contractual rights to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Derek F. Newton
Derek F. Newton, P.E. 97689
Vice President

Date Signed: January 31, 2012

By: /s/ Patrick L. Higgs
Patrick L. Higgs, P.G. 985
Vice President

Date Signed: January 31, 2012

DFN:JLJ

NETHERLAND, SEWELL & ASSOCIATES, INC.
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C.H. (SCOTT) REES III
PRESIDENT & COO
DANNY D. SIMMONS
EXECUTIVE VP
G. LANCE BINDER

EXECUTIVE COMMITTEE
P. SCOTT FROST - DALLAS
J. CARTER HENSON, JR. - HOUSTON
DAN PAUL SMITH - DALLAS
JOSEPH J. SPELLMAN - DALLAS
THOMAS J. TELLA II - DALLAS

February 2, 2012

Mr. W. Russell Scheirman, II
VAALCO Energy, Inc.
4600 Post Oak Place, Suite 309
Houston, Texas 77027

Dear Mr. Scheirman:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2011, to the VAALCO Energy, Inc. (VAALCO) interest in certain oil and gas properties located in Texas and federal waters in the Gulf of Mexico. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute approximately 6 percent of all proved reserves owned by VAALCO. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for VAALCO's use in filing with the SEC; in our opinion, the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the VAALCO interest in these properties, as of December 31, 2011, to be:

| | Net Reserves | | Future Net Revenue (M$) | |
|---|---|---|---|---|
| Category | Oil (MBBL) | Gas (MMCF) | Total | Present Worth at 10% |
| Proved Developed Producing | 18.5 | 855.7 | 4,583.4 | 3,018.8 |
| Proved Undeveloped(1) | 17.0 | 1,069.2 | 1,502.6 | -82.7 |
| Total Proved | 35.5 | 1,924.9 | 6,086.0 | 2,936.1 |

(1) Estimates of proved undeveloped reserves have been included for the Hefley 90-2H well, which generates positive future net revenue but has negative present worth discounted at 10 percent based on the constant prices and costs discussed in subsequent paragraphs of this letter.

The oil reserves shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved developed producing and proved undeveloped reserves. Our study indicates that there are no proved developed non-producing reserves for these properties at this time. As requested, probable reserves that exist for these properties have not been included. No study was made to determine whether possible reserves might be established for these properties. Estimates of proved undeveloped reserves have been included for the Hefley 90-2H well, which generates positive future net revenue but has negative present worth discounted at 10 percent based on the constant prices and costs discussed in subsequent paragraphs of this letter. This location has been included because VAALCO has already begun drilling this well. The substantial investment remaining prohibits us from categorizing this well as proved developed non-producing. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

4500 THANKSGIVING TOWER • 1601 ELM STREET • DALLAS, TEXAS 75201-4754 • PH: 214-969-5401 • FAX: 214-969-5411 nsai@nsai-petro.com
1221 LAMAR STREET, SUITE 1200 • HOUSTON, TEXAS 77010-3072 • PH: 713-654-4950 • FAX: 713-654-4951 netherlandsewell.com

Gross revenue shown in this report is VAALCO's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for VAALCO's share of production taxes and ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2011. For oil volumes, the average West Texas Intermediate posted price of $92.71 per barrel is adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub spot price of $4.118 per MMBTU is adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $78.89 per barrel of oil and $5.439 per MCF of gas.

Operating costs used in this report are based on operating expense records of VAALCO. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Headquarters general and administrative overhead expenses of VAALCO are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are held constant throughout the lives of the properties.

Capital costs used in this report were provided by VAALCO and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for new development wells and production equipment. Based on our understanding of VAALCO's future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are VAALCO's estimates of the costs to abandon the wells, net of any salvage value. It is our understanding that the estimated abandonment costs are equal to salvage value. Capital costs and abandonment costs are held constant to the date of expenditure.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the VAALCO interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on VAALCO receiving its net revenue interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for an undeveloped location and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from VAALCO, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Derek F. Newton
Derek F. Newton, P.E. 97689
Vice President

Date Signed: February 2, 2012

DFN:JLJ