

ISRAMCO INC
Form 10-K
March 17, 2014

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, 2013
- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES
EXCHANGE ACT OF 1934

COMMISSION FILE NUMBER: 0-12500

ISRAMCO, INC.

(Exact name of registrant as specified in its charter)

Delaware
(State or Other Jurisdiction of Incorporation)

13-3145265
(IRS Employer Identification No.)

2425 West Loop South, Suite 810, Houston Texas 77027
(Address of Principal Executive Offices)

713-621-6785
(Registrant's Telephone Number, including Area Code)

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

Securities registered under Section 12(g) of the Exchange Act:
Common Stock, par value \$0.01
(Title of Class)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

Indicate by check mark whether the registrant 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 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 Securities Exchange Act). Yes No

As of March 17, 2014, there were 2,717,691 shares of the Registrant's common stock par value \$0.01 per share ("Common Stock") outstanding. The aggregate the Common Stock held by non-affiliates of the Registrant at March 13, 2014, based on the last sale price of such equity reported on Nasdaq Market, market value of was approximately \$376 million.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant's Form 10-K/A which will be filed on or before April 30, 2014.

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ISRAMCO, INC.
2013 FORM 10-K ANNUAL REPORT

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Special note regarding forward-looking statements

This report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achieve,” “anticipate,” “will,” “continue,” “potential,” “should,” “could” and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. The actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the “Risk Factors” section of this report and other sections of this report that describe factors that could cause our actual results to differ from those set forth in the forward-looking statements, including, but not limited to, the following factors:

- the timing and extent of changes in prices for, and demand for, crude oil and condensate, NGLs, natural gas and related commodities;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the possibility that production decline rates for some of our oil and gas producing properties are greater than we expect;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the ability to replace oil and natural gas reserves;
- increased labor costs or unavailability of skilled workers;
- environmental risks;
- drilling and operating risks;
- the loss of one or more of our larger customers;
- our ability to implement price increases or maintain pricing on our core services;
- exploration and development risks;
- competition, including competition for acreage in oil and gas producing areas and for experienced personnel;
- management’s ability to execute our plans to meet our goals;
- our ability to retain key members of senior management and key technical employees;

- industry capacity;
- employee turnover and our ability to replace or add qualified workers;
- severe weather impacts on our business;
- operating risks and the possibility that our insurance may not be adequate to cover all of our losses or liabilities;
- our ability to repay our debt when due;
- our ability to obtain goods and services, such as drilling rigs and tubulars, and access to adequate gathering systems and pipeline take-away capacity, to execute our drilling and development programs;
- general economic and regulatory conditions, whether internationally, nationally, or in the regional and local market areas in which we do business, may be less favorable than expected.
- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or commodity prices.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled “Risk Factors” included in this report. All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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PART I

ITEM 1. BUSINESS

Overview

Istramco, Inc., (NASDAQ: ISRL) is a Delaware corporation incorporated in 1982 (hereinafter, “we”, the “Company” or “Istramco”). The Company together with its subsidiaries is an independent oil and natural gas company, engaged in the exploration, development and production of predominately oil and natural gas properties located onshore in the United States and off shore Israel. The Company also operates a well service company that provides a full range of onshore well services to oil companies and independent oil and natural gas production companies conducting operations in the United States.

We currently conduct our operations through two operating segments: our Exploration, Development and Production Segment and our Production Services Segment. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 12, Segment Information, of the Notes to Consolidated Financial Statements, included in Part II, Item 8, Financial Statements and Supplemental Data, of this Annual Report on Form 10-K.

Exploration, Development and Production Segment

At December 31, 2013, our estimated total proved oil, natural gas reserves and natural gas liquids, as prepared by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc., were approximately 41,035 thousand barrels of oil equivalent (“MBOE”), consisting of 2,874 thousand barrels (MBbls) of oil, 218,990 million cubic feet (MMcf) of natural gas and 1,662 thousand barrels (MBbls) of natural gas liquids. Approximately 86.1% of our proved reserves were classified as proved developed (See Note 15, Supplemental Oil and Gas Information to Consolidated Financial Statements to our consolidated financial statements). Full year 2013 production averaged 3.1 MBOE/d compared to 2.17 MBOE/d in 2012. Tamar Field production share amounted to 1.26 MBOE/d out of total 3.1 MBOE/d compared to 0 MBOE/d in 2012.

United States

We, through our wholly-owned subsidiaries, are involved in oil and gas exploration, including the development, production and operation of wells in the United States. We own varying working interests in oil and gas wells in Louisiana, Texas, New Mexico, Oklahoma, Wyoming, Utah and Colorado and currently serve as operator of approximately 589 producing wells most of which are located in Texas and New Mexico.

Israel

In 2007, we closed our branch in Israel in order to focus on our expanding presence in the United States. Despite the closure of that branch we retained certain overriding royalties in three oil and gas licenses located offshore Israel. These licenses granted by the government of Israel known as the “Michal”, “Matan” and “Shimson” Licenses.

In 2009, two natural gas discoveries, known as “Tamar” and “Dalit”, were made within the area covered by Michal and Matan Licenses, respectively. In December 2009, the Israeli Petroleum Commissioner granted Noble Energy, Inc. (“Noble”) and its partners, Istramco Negev 2-LP, Delek Drilling, Avner Oil & Gas, and Dor Gas (the “Tamar Consortium”), two leases (the “Tamar Lease” and the “Dalit Lease”). The Leases are scheduled to expire in December 2038 and cover the Tamar and Dalit gas fields (collectively the “Tamar Field”). The Tamar Field is approximately 95 kilometers off the coast of the Israel, in the Israel exclusive economic zone of the Eastern Mediterranean, with a water

depth of approximately 1,700 meters.

We own an overriding royalty interest of 1.5375% in the Tamar Field, which will increase to 2.7375% after payout (collectively the “Tamar Royalty”). An overriding royalty interest is an ownership interest in the oil and gas leasehold estate equating to a certain percentage of production or production revenues, calculated free of the costs of production and development of the underlying lease(s), but subject to its proportionate share of certain post production costs. An overriding royalty interest is a non-possessory interest in the oil and gas leasehold estate and, accordingly,, we have no control over the operations, drilling, expenses, timing, production, sales, or any other aspect of development or production of the Tamar Field.

Production from the Tamar Field commenced in March 2013. The Tamar Field is now operational and delivering significant volumes of natural gas to Israel. The natural gas flows from the Tamar Field through the world's longest subsea tieback, more than 90 miles to the Tamar platform, and then to the Ashdod onshore terminal (AOT).

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Tamar partners currently sells natural gas from the Tamar Field, to the Israel Electric Corporation (“IEC”) and numerous other Israeli purchasers, including independent power producers, cogeneration facilities, local distribution companies and certain industrial companies. Currently, most gas sale and purchase agreements provide for the sales for a 7 to 15 year term. Depending on the specific contract, prices vary and are based on an initial base price subject to price adjustment provisions, including price indexation and a price floor. The IEC contract provides for price reopeners (sometimes referred to as “price review” clauses) in the eighth and eleventh years of the contract, subject to limits on the amount of increase or decrease from the existing contractual price.

During year ended December 31, 2013, net sales from the Tamar Field attributable to Isramco amounted to 2,736,000 Mcf of natural gas and 3,788 Bbl of condensate with prices of \$5.69 per Mcf and \$99.79 per Bbl of condensate. Total revenues net of marketing and transportation expenses were \$15,824,000. The Israeli Tax Authority withheld \$3,956,000, of this revenue which is recognized as an asset on the Company’s balance sheet.

We have a third party reserve report from independent petroleum engineers, Netherland, Sewell & Associates, Inc. dated March 14, 2014 estimating reserves allocable to the Tamar Royalty as of December 31, 2013 (the “Tamar Reserve Report”). This reserve report estimates that by reason ownership of the Tamar Royalty, we have proven reserves estimated at 199,261 million cubic feet of natural gas and 259 thousand barrels of natural gas liquids. The Tamar Reserve Report indicates that the undiscounted estimated future net revenue (after deduction of estimated production and ad valorem taxes but before estimated income tax and levy) for such reserves (paid out over time) at \$802,178,000. The Tamar Reserve Report estimates the net present worth of such reserves, discounted at 10% annual discount rate factor, at \$354,200,000 (See Note 15, Supplemental Oil and Gas Information to Consolidated Financial Statements to our consolidated financial statements). The gas price used to value the reserves in the Tamar Reserve Report is based on contractual arrangements, in accordance with SEC rules. The report indicates that there are no commercial oil deposits included as reserves.

The amount of proceeds we receive from Tamar Royalty is contingent on a variety of factors, including the timing of production, the price received, and our proportionate share of certain costs and expenses associated with Tamar Field operations. . In the event of payout the Tamar Royalty increases after Payout of the Tamar Field and, accordingly, the Tamar Royalty will be subject to a corresponding increase in certain costs and expenses. Payout is the point when all the costs of leasing, drilling, producing and operating the leases have been recovered from lease production proceeds, as defined in the royalty agreement under which Isramco acquired its interest.

As we do not control any of those factors affecting our payments (time of production, price received, costs incurred) and based on that and the other risk factors as set out herein it is difficult to determine the amounts or timing of any amounts we receive with precision or when payout is likely to occur, if ever. Based on the reserves and anticipated production, the income from the Tamar Royalty is currently expected to be very significant to the Company for the foreseeable future.

Commercial production of the Tamar reserves is subject to numerous major risks. These risks include all of the typical risks associated with offshore oil and gas production. Commercial production of such reserves is also subject to additional major risks that may be unique to the Tamar Field. These include:

- There has been no previous large scale production of natural gas from offshore Israel. Therefore, there may be geological, geophysical, or other unforeseen problems unique to offshore Israel that could affect production. In addition, because of the lack of comparable production history for this part of offshore Israel, the length of time that large scale production from offshore Israel can be sustained is uncertain
- There has been significant political upheaval and unrest in the Middle East, particularly in Syria and Egypt. In addition, there is considerable hostility between Israel and other countries in the region. Accordingly, there is

significant risk that production from the Tamar Field may be delayed, diminished, or prevented by virtue of war, acts of terrorism, or other similar or dissimilar events of force majeure.

- The market for natural gas in Israel exists, but the financial ability of customers of the Tamar Consortium to take and pay for material amounts of such natural gas remains unclear. It is uncertain that existing customers and markets are capable of buying all of the anticipated production from the Tamar Field.

A well was drilled in the area covered by the Shimshon License and an application has been filed to recognize this well as a commercial discovery and, thereby, extend the terms of the License for an additional two years. There has been no ruling on this application and no reserves have been booked relating to this License.

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Production Service Segment

The Company's began well service operations in October, 2011. Our well servicing rig fleet provides a range of well services, including the completion of newly-drilled wells, maintenance and workover of existing wells, and plugging and abandonment of wells at the end of their useful lives to a diverse group of oil and gas exploration and production companies.

Completion Service. Newly drilled wells require completion services to prepare the well for production. Well servicing rigs are frequently used to complete newly drilled wells to minimize the use of higher cost drilling rigs in the completion process. The completion process may involve selectively perforating the well casing in the productive zones to allow oil or gas to flow into the well bore, stimulating and testing these zones, and installing the production string and other downhole equipment. The completion process typically ranges from a few days to several weeks, depending on the nature and type of the completion, and generally requires additional auxiliary equipment in addition to a well service rigs. The demand for completion services is directly related to drilling activity levels, which are sensitive to fluctuations in oil and gas prices.

Well-servicing/Maintenance Services. We provide maintenance services on the mechanical apparatus used to pump or lift oil from producing wells. These services include, among other activities, repairing and replacing pumps, sucker rods and tubing. We provide the rigs, equipment and crews for these tasks, which are performed on both oil and natural gas wells, but which are more commonly required on oil wells. Maintenance services typically take less than 48 hours to complete. Rigs generally are provided to customers on a call-out basis.

Workover Services. Producing oil and natural gas wells occasionally require major repairs or modifications, called "workovers." Workovers may be required to remedy failures, modify well depth and formation penetration to capture hydrocarbons from alternative formations, clean out and recomplete a well when production has declined, repair leaks or convert a depleted well to an injection well for secondary or enhanced recovery projects. Workovers normally are carried out with pumps and tanks for drilling fluids, blowout preventers, and other specialized equipment for servicing rigs. A workover may last anywhere from a few days to several weeks.

Plugging Services. Well servicing rigs are also used in the process of permanently closing oil and gas wells no longer capable of producing in economic quantities. Many well operators bid this work on a "turnkey" basis, requiring the service company to perform the entire job, including the sale or disposal of equipment salvaged from the well as part of the compensation received, and complying with state regulatory requirements. Plugging and abandonment work can provide favorable operating margins and is less sensitive to oil and gas pricing than drilling and workover activity since well operators must plug a well in accordance with state regulations when it is no longer productive. We perform plugging and abandonment work throughout our core areas of operation in conjunction with equipment provided by us or by other service companies.

We typically bill clients for our well servicing on an hourly basis for the period that the rig is actively working. As of December 31, 2013, our fleet of well servicing rigs totaled 27 rigs, which we operate through 6 locations in Texas and New Mexico. Our fleet is among the newest in the industry, is capable of working at depths of 21,000 feet, and as of December 31, 2013, consists of one 600 horsepower rig, twenty four 550 horsepower rigs, and two 300 horsepower rigs.

Derivative Instruments and Hedging Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We may hedge a substantial, but varying, portion of our anticipated

oil and natural gas production for the next years. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to our derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the consolidated statements of operations. We carry our derivatives at fair value on our consolidated balance sheets, with the changes in the fair value included in our consolidated statements of operations in the period in which the change occurs. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

On March 9, 2010, pursuant to an agreement with Wells Fargo & Company, the derivative contracts between Isramco and Wells Fargo were terminated and the Company signed new swap contracts with Macquarie Bank, N.A. for an aggregate volume of 336,780 barrels of crude oil during the 46 month period commencing March 2011.

On August 15, 2012, pursuant to an agreement with Macquarie Bank, the derivative contracts between Isramco and Macquarie Bank were terminated early and the Company received an amount of \$1,737,000 for outstanding hedge positions.

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Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with many other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. There are also many well service companies that compete for the same customers as we compete. The primary areas in which we encounter substantial competition are in locating and acquiring attractive producing oil and natural gas properties, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees during active times in the oil and gas industry. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and in some instances individual states where we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Our well service customers include major oil companies and mid range independent oil and natural gas production companies. The markets in which we operate are highly competitive. Competition is influenced by such factors as price, capacity, availability of work crews, and reputation and experience of the service provider. We believe that an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced, skilled and well-trained work force. We believe many of our large customers place increased emphasis on the safety, performance and quality of the crews, equipment and services provided by their contractors. Although we believe customers consider all of these factors, price is often the primary factor in determining which service provider is awarded the work. However, in numerous instances, we secure and maintain work for large customers for which efficiency, safety, technology, size of fleet and availability of other services are of equal importance to price.

Markets and Major Customers

Through our wholly-owned subsidiary, we operate a substantial portion of our domestic oil and natural gas properties. As the operator of a property, the Company makes full payment of the costs associated with each property and seeks reimbursement from the other working interest owners in the property for their share of those costs. Isramco's joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the Company's joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts as to its sales of oil and gas production. The Company does not believe the loss of any one of its purchasers would materially affect the Company's ability to sell the oil and natural gas it produces. The Company believes other purchasers are available in the Company's areas of operations.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can disrupt our overall business plans. Demand for natural gas is typically higher in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other circumstances may cause accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment, or cause significant injury to persons or property. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties.

We carry insurance against such hazards. However, as is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business, either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position and results of operations. For further discussion on risks, see Item 1A. Risk Factors.

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Regulations

We do not have any offshore operations in the United States. However, all of the jurisdictions in which we own or operate oil and natural gas properties regulate exploration for and production of oil and natural gas. These laws and regulations include provisions requiring permits to drill wells and requirements that we obtain and maintain a bond or other security as a condition to drilling or operating wells. Regulations also specify the permitted location of and method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells.

Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in a given area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. The effect of these regulations is to potentially limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability.

Each state in which we operate also imposes some form of production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We are liable for paying this tax on our production, and are also liable for various real and personal property taxes on our leases and facilities.

Environmental and Occupational Health and Safety Regulations

The oil and gas industry in the United States is subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Many governmental agencies, such as the United States Environmental Protection Agency (the "EPA") have issued lengthy and comprehensive regulations to implement and enforce these laws. These laws and regulations often require difficult and costly compliance measures. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities.

In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup costs without regard to negligence or fault on the part of that person. We endeavor to fully comply with these regulatory requirements; however, compliance increases our costs and consequently affects our profitability.

As a part of the overall environmental regulatory policy, the permitting, construction and operations of certain oil and gas facilities are regulated. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Once operational, enforcement measures can include significant civil penalties for regulatory violations, regardless of intent. Under appropriate circumstances, an administrative agency can issue a cease and desist order to require termination of operations.

Environmental regulation is becoming more comprehensive and additional programs, as well as increased obligations under existing programs, are anticipated. In this regard, we expect additional regulation of naturally occurring radioactive materials, oil and natural gas exploration and production operations, waste management, and underground

injection of water and waste material. The adoption of additional regulations could have a material adverse effect on our financial condition and results of operations. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

Compliance with environmental laws and regulations increases Company's overall cost of business, but has not had, to date, a material adverse effect on its operations, financial condition or results of operations. It is not anticipated, based on current laws and regulations, that Isramco will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to its total exploration and development expenditure program in order to comply with such laws and regulations. However, given that such laws and regulations are subject to change, Isramco is unable to predict the ultimate cost of compliance or the ultimate effect on its operations, financial condition and results of operations.

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Comprehensive Environmental Response, Compensation and Liability Act and Hazardous Substances

In 1980, the United States Congress enacted the federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law. This law, which has been amended since enactment, and comparable state laws impose strict liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of what are considered to be “hazardous substances” into the environment. These persons include the current or former owners or operators of the sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances released at the site. Under CERCLA, we may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment whether or not we are responsible for the release or even owned the site at the time of the release, as well as for damages to natural resources and for the costs of health studies. In addition, companies that incur liability frequently confront additional claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Solid Waste Disposal Act and Waste Management

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, regulates the disposal of solid waste but generally excludes most wastes generated by the exploration and production of oil and natural gas, such as drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies as non-hazardous wastes as long as these wastes are not commingled with regulated hazardous wastes. Moreover, in the ordinary course of our operations, other wastes generated in connection with our exploration and production activities may be regulated as hazardous waste under RCRA or hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate these materials or wastes. At this time it is not possible to estimate the potential liabilities to which we may be subject from unknown, latent liability risks with respect to any properties where materials or wastes may have been released, but of which we have not been made aware.

The Clean Water Act, wastewater and storm water discharges

The oil and gas industry, and our operations, are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, we may apply for storm water discharge permit coverage and updating storm water discharge management practices at some of our facilities. We believe that we will be able to obtain, or be included under, these permits, where necessary, and be required make only minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages.

These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. More specifically, we are required to develop and maintain a plan applicable to each of our properties at which any significant volume of crude oil or other substance is stored and to ensure the site has sufficient protections (such as berms, etc.) to ensure that any spill will be contained

and not reach navigable waters.

The Safe Drinking Water Act, groundwater protection, and the Underground Injection Control Program

The federal Safe Drinking Water Act (SWDA), the Underground Injection Control (UIC) program promulgated under the SWDA and state programs all regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others the responsibility for the program has been delegated to the state. This program requires that a permit be obtained before drilling salt water disposal well. Monitoring the integrity of well casing must also be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Violation of these regulations and/or contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

We have not heretofore engaged in extensive hydraulic fracturing or other well stimulation services on the wells for which we are the operator and when we do we engage third parties to conduct these operations on our behalf.

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The Clean Air Act

The federal Clean Air Act, enacted in 1970, and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. The EPA has developed and continues to develop stringent regulations under the authority of the Clean Air Act governing emissions of toxic air pollutants from specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations.

Some of our operations are located in areas designated as “non-attainment” areas, which are geographic areas that do not meet the federal air quality standards. Air emission controls and requirements in non-attainment areas are generally more stringent than those imposed in other areas, and the construction of new, or expansion of existing, sources may be restricted.

Climate change legislation and greenhouse gas regulation

The issue of “global warming” has attracted significant attention and many believe that emissions of certain gases contribute to this problem. Many nations have agreed to limit emissions of “greenhouse gases” pursuant to the United Nations Framework Convention on Climate Change, and the “Kyoto Protocol.” Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered “greenhouse gases” regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products.

In summary, we may be subject to EPA greenhouse gas monitoring and reporting rules, and potentially new EPA permitting rules if adopted, that would apply greenhouse gas permitting obligations and emissions limitations under the federal Clean Air Act. Whether or not any federal greenhouse gas regulations are enacted, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed, including the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

The National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have 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. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are potentially subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties, may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat, or natural resources resulting from drilling, construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek compensation for alleged natural resources damages and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communications and community right to know statutes, including, but not limited to, the federal Emergency Planning and Community Right-to- Know Act, and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances.

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Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

Hydraulic Fracturing

There have been several regulatory and governmental initiatives to restrict the hydraulic-fracturing process, which could have an adverse impact on our completion or production activities. The U.S. Environmental Protection Agency (EPA) has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic-fracturing practices notwithstanding the existence of current oil and gas regulations adopted at the state level. Moreover, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected to be available by 2014. In addition, in April 2012, the EPA issued the first federal air standards for natural gas wells that are hydraulically fractured, which will require operators to significantly reduce volatile organic compounds or VOC emissions through the use of “green completions” to capture natural gas that would otherwise escape into the air. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or “green”) completions must be used. The rules also establish specific new requirements, which were effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On September 23, 2013, the EPA published amendments to the rule which would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. The EPA is continuing to consider other aspects of the new rules and may propose additional amendments by the end of 2013 or in early 2014. These rules may require a number of modifications to our operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

The EPA has also announced plans to propose effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities by 2014. Certain other governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices, including evaluations by the U.S. Department of Energy and the DOI, and coordination of an administration-wide review of these practices by the White House Council on Environmental Quality. Congress is currently considering, and has from time to time in the past considered, bills that would regulate hydraulic fracturing and/or require public disclosure of chemicals used in the hydraulic-fracturing process. A number of states, including states in which we operate, have adopted or are considering legal requirements that could impose more stringent permitting, public disclosure, and well-construction requirements on hydraulic-fracturing activities.

These laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company’s activities in a particular area. Compliance with these laws and regulations also, in most cases, requires new or amended permits that may contain new or more stringent technological standards or limits on emissions, discharges, disposals, or other releases in

association with new or modified operations. Application for these permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with public notice and comment periods required prior to the issuance or amendment of a permit as well as the agency's processing of an application. Many of the delays associated with the permitting process are beyond the control of the Company.

Many states where the Company operates also have, or are developing, similar environmental laws, regulations, or analogous controls governing many of these same types of activities. While the legal requirements may be similar in form, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the development of a project or substantially increase the cost of doing business.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards, such as air emission standards and water quality standards, continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change and the threat of adverse impacts to groundwater arising from hydraulic-fracturing activities, are expected to continue to have an increasing impact on the Company's operations.

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Climate Change

Policymakers in the U.S. are increasingly focusing on whether the emissions of greenhouse gases, such as carbon dioxide and methane, are contributing to harmful climatic changes. Policymakers at both the U.S. federal and state levels have introduced legislation and proposed new regulations that are designed to quantify and limit the emission of greenhouse gases through inventories, limitations and/or taxes on greenhouse gas emissions. Legislative initiatives and discussions to date have focused on the development of cap-and-trade and/or carbon tax programs. A cap-and-trade program generally would cap overall greenhouse gas emissions on an economy-wide basis and require major sources of greenhouse gas emissions or major fuel producers to acquire and surrender emission allowances. Cap-and-trade programs could be relevant to us and our operations in several ways. First, the equipment we use to explore for, develop, produce and process oil and natural gas emits greenhouse gases. We could therefore be subject to caps, and penalties if emissions exceeded the caps. Second, the combustion of carbon-based fuels, such as the oil, gas and NGLs we sell, emits carbon dioxide and other greenhouse gases. Therefore, demand for our products could be reduced by imposition of caps and penalties on our customers. Carbon taxes could likewise affect us by being based on emissions from our equipment and/or emissions resulting from use of our products by our customers. Of overriding significance would be the point of regulation or taxation. Application of caps or taxes on companies such as Isramco, based on carbon content of produced oil and gas volumes rather than on consumer emissions, could lead to penalties, fees or tax assessments for which there are no mechanisms to pass them through the distribution and consumption chain where fuel use or conservation choices are made. Moreover, because oil and natural gas are used as chemical feedstocks and not solely as fossil fuel, applying a carbon tax to oil and gas at the production stage would be excessive with respect to actual carbon emissions from petroleum fuels.

Employees

As of December 31, 2013, we had 228 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Available Information

We file annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Isramco, Inc., that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov.

ITEM 1A. RISK FACTORS

In addition to the other information contained in this Annual Report on Form 10-K, investors should consider carefully the following risk factors, which may not be the only risks we face, as our business and operations may also be subject to risks that we do not yet know of, or that we currently believe are immaterial. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could be materially and adversely affected and the trading price of our common stock could decline.

Oil, natural-gas and NGLs prices are volatile. A substantial or extended decline in prices could adversely affect our financial condition and results of operations.

Prices for oil, natural gas and NGLs ((Natural Gas Liquids) can fluctuate widely. Our revenues, operating results and future growth rates are highly dependent on the prices we receive for our oil, natural gas and NGLs. Historically, the markets for oil, natural gas and NGLs have been volatile and may continue to be volatile in the future. For example, in recent years market prices for natural gas in the United States have declined substantially from the highs achieved in 2008 and the rapid development of shale plays throughout North America has contributed significantly to this trend, however, during the period of 2012 and 2013 gas prices have trended in a relatively stable manner. Factors influencing the prices of oil, natural gas and NGLs are beyond our control. These factors include, among others:

- the worldwide military and political environment, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities or further acts of terrorism in the United States, or elsewhere, particularly Israel;

- worldwide and domestic supplies of crude oil, natural gas and NGLs;

- actions taken by foreign oil and gas producing nations;

- the level of global crude oil and natural gas inventories;

- further application of horizontal drilling techniques which could increase production and significantly impact both domestic and global supplies of crude oil, natural gas, and NGLs;

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the price and level of foreign imports of oil, natural gas and NGLs;
the effect of worldwide energy conservation efforts;
the price and availability of alternative and competing fuels;
Organization of Petroleum-Exporting Countries (OPEC) spare capacity relative to global crude oil supply;
the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs;
the availability of pipeline capacity and infrastructure;
the availability of crude oil transportation and refining capacity;
consumer demand for oil, gas and NGLs;
the growth of consumer product demand in emerging markets, such as India and China;
fuel efficiency regulations, such as the Corporate Average Fuel Economy (CAFE) standards, and its impacts on crude oil demand as a transportation fuel;
labor unrest in oil and natural gas producing regions;
regional pricing differentials;
weather conditions;
electricity needs;
the nature and extent of domestic and foreign governmental regulation (including environmental regulation and regulation of derivatives transactions and hedging activities) and taxation; and
the overall economic environment.

The long-term effect of these and other factors on the prices of oil, natural gas and NGLs are uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations;
reducing the amount of oil, natural gas and NGLs that we can produce economically;
causing us to delay or postpone some of our capital projects;
reducing our revenues, operating income and cash flows;
reducing the carrying value of our crude oil and natural gas properties;
reducing the amounts of our estimated proved oil and natural-gas reserves;
reducing the standardized measure of discounted future net cash flows relating to oil and natural-gas reserves; and
limiting our access to sources of capital, such as equity and long-term debt; and
additional counterparty credit risk exposure on commodity hedges.

Depending on the market prices of oil and gas, oil and gas exploration and production companies may cancel or curtail their drilling programs and may lower production spending on existing wells, thereby reducing demand for our production services. Many factors beyond our control affect oil and gas prices, including:

the cost of exploring for, producing and delivering oil and gas;
the discovery rate of new oil and gas reserves;
the rate of decline of existing and new oil and gas reserves;
the ability of oil and gas exploration and production companies to raise capital;
economic conditions in the United States, Israel and elsewhere;
the price of foreign imports of oil and gas.

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Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, state, tribal, local and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, hydraulic fracturing and environmental protection regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, tribal and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws, including environmental and tax laws, and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For example, currently proposed federal legislation, that, if adopted, could adversely affect our business, financial condition and results of operations, includes the following:

Climate Change A number of state and regional efforts have emerged that are aimed at tracking and/or reducing emissions of green-house gases (GHGs). In addition, the U.S. Environmental Protection Agency (EPA) has made findings that emissions of GHGs present a danger to public health and the environment and, based on these findings, has adopted regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. We may be required to install “best available control technology” to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs.

Taxes. Congress may undertake significant deficit reduction or comprehensive tax reform in the coming year. Proposals include provisions that would, if enacted, (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) eliminate the manufacturing deduction for oil and gas qualified production activities, and (iii) eliminate the acceleration of depreciation for tangible property.

Hydraulic Fracturing. This process is an essential and common practice used to stimulate production of natural gas and/or oil from dense subsurface rock formations such as shales that generally exist between 4,000 and 14,000 feet below ground. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The process is typically regulated by state oil and natural-gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels with the public comment period expiring in August 2012. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently projects to issue an Advance Notice of Proposed Rulemaking in May 2013 that would seek public input on the design and scope of such disclosure regulations. In May 2012, the Department of the Interior (DOI) released draft regulations governing hydraulic fracturing on federal and Indian oil and gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing, and monitoring of well-stimulation operations. In addition, Congress, from time to time, has considered adopting

legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

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Certain states in which we operate, including, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and additional well-construction requirements on hydraulic-fracturing operations. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic-fracturing activities. Nonetheless, in the event state or local restrictions are adopted in areas where we currently conduct operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements. These costs may be significant in nature, and we may experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

There are also certain governmental reviews recently conducted or underway that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012, and a final draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities and plans to propose these standards for shale gas by 2014. In addition, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods and, in August 2011, issued a report on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale-gas development. Also, as discussed above, the DOI is pursuing regulations governing hydraulic fracturing on federal and Indian oil and gas leases. These studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays. The adoption of any federal, state or local laws or the implementation of regulations or ordinances restricting or increasing the costs of hydraulic fracturing could cause a decrease in the completion of new oil and natural gas wells and an associated decrease in demand for our drilling and well servicing activities, any or all of which could adversely affect our financial position, results of operations and cash flows.

The federal Clean Water Act, as amended by the Oil Pollution Act, the federal Clean Air Act, the federal Resource Conservation and Recovery Act, the federal Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Safe Drinking Water Act, or SDWA, the federal Outer Continental Shelf Lands Act, the Occupational Safety and Health Act, or OSHA, and their state counterparts and similar statutes are the primary statutes that impose the requirements and provide for civil, criminal and administrative penalties and other sanctions for violation of their requirements. The OSHA hazard communication standard, the Environmental

Protection Agency “community right-to-know” regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and report information about the hazardous materials we use in our operations to employees, state and local government authorities and local citizens. In addition, CERCLA, also known as the “Superfund” law, and similar state statutes impose strict liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered responsible for the release or threatened release of hazardous substances into the environment. These persons include the current owner or operator of a facility where a release has occurred, the owner or operator of a facility at the time a release occurred, and companies that disposed of or arranged for the disposal of hazardous substances found at a particular site. This liability may be joint and several. Such liability, which may be imposed for the conduct of others and for conditions others have caused, includes the cost of removal and remedial action as well as damages to natural resources. Few defenses exist to the liability imposed by environmental laws and regulations. It is also common for third parties to file claims for personal injury and property damage caused by substances released into the environment.

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The enactment of derivatives legislation 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 (Dodd-Frank Act), enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC 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. The position-limits rule was vacated by the U.S. District Court for the District of Columbia in September 2012 and the CFTC recently stated that it will appeal the District Court's decision. The CFTC also finalized other regulations, including critical rulemakings on the definition of "swap," "swap dealer," and "major swap participant." Some regulations, however, remain to be finalized and it is not possible at this time to predict when this will be accomplished. Depending on the Company's classification and the particular nature of its derivative activities, the Dodd-Frank Act and regulations may require the Company to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities. The Dodd-Frank Act and regulations may also require the counterparties to the Company's derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and 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, reduce the availability of derivatives to protect against risks the Company encounters, reduce the Company's ability to monetize or restructure its existing derivative contracts, and increase the Company's exposure to less-creditworthy counterparties. If the Company reduces its use of derivatives as a result of the Dodd-Frank Act and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act 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. The Company's revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows.

Drilling crude oil and natural gas wells is a high-risk activity and subjects us to a variety of risks that we cannot control.

Drilling crude oil and natural gas wells, including development wells, involves numerous risks, including the risk that we may not encounter commercially productive crude oil and natural gas reserves (including "dry holes"). As a result, we may not recover all or any portion of our investment in new wells.

Specifically, we often are uncertain as to the future cost or timing of drilling, completing and operating wells, and our drilling operations and those of our third-party operators may be curtailed, delayed or canceled, the cost of such operations may increase and/or our results of operations and cash flows from such operations may be impacted, as a result of a variety of factors, including

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions, such as winter storms, flooding and hurricanes, and changes in weather patterns;

compliance with, or changes in, environmental laws and regulations relating to air emissions, hydraulic fracturing and disposal of produced water, drilling fluids and other wastes, laws and regulations imposing conditions and restrictions on drilling and completion operations and other laws and regulations, such as tax laws and regulations;

the availability and timely issuance of required governmental permits and licenses;

the availability of, costs associated with and terms of contractual arrangements for properties, including mineral licenses and leases, pipelines, rail cars, crude oil hauling trucks and qualified drivers and related facilities and equipment to gather, process, compress, transport and market crude oil, natural gas and related commodities; and

the costs of, or shortages or delays in the availability of, drilling rigs, hydraulic fracturing services, pressure pumping equipment and supplies, tubular materials, water, sand, disposal facilities, qualified personnel and other necessary equipment, materials, supplies and services.

Our failure to recover our investment in wells, increases in the costs of our drilling operations or those of our third-party operators, and/or curtailments, delays or cancellations of our drilling operations or those of our third-party operators in each case due to any of the above factors or other factors, may materially and adversely affect our business, financial condition and results of operations. For related discussion of the risks and potential losses and liabilities inherent in our crude oil and natural gas operations generally, see the immediately following risk factor.

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Our oil and natural gas activities are subject to various risks that are beyond our control and expose us to potential losses and liabilities, and insurance may not fully protect us against these risks and potential losses and liabilities.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;

blowouts, fires, explosions, loss of well control, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;

unavailability of materials and equipment;

engineering and construction delays;

unanticipated transportation costs and delays;

adverse weather conditions, such as winter storms, flooding and hurricanes, and other natural disasters;

hazards resulting from unusual or unexpected geological or environmental conditions;

environmental regulations and requirements;

accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;

changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;

fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production;

hazards resulting from the presence of hydrogen sulfide (H₂S) or other contaminants in gas we produce;

the availability of alternative fuels and the price at which they become available; and

terrorism, vandalism and physical, electronic and cyber security breaches.

To mitigate financial losses resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/control of a well, comprehensive general liability, aviation liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against all of potential losses arising as a result of the foregoing, and for certain risks, such as political risk,

business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

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The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. During these periods, the costs of rigs, equipment, supplies, and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

A portion of our crude oil and natural gas production may be subject to interruptions that could have a material and adverse effect on us.

A portion of our crude oil and natural gas production may be interrupted, or shut in, from time to time for various reasons, including, but not limited to, as a result of accidents, weather conditions, loss of gathering, processing, compression or transportation facility access or field labor issues, or intentionally as a result of market conditions such as crude oil or natural gas prices that we deem uneconomic. If a substantial amount of our production is interrupted, our cash flows and, in turn, our financial condition and results of operations could be materially and adversely affected.

Failure to fund continued capital expenditures could adversely affect our properties.

Our acquisition, exploration, and development activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flows from operations and loans from commercial banks and related parties. Future cash flows are subject to a number of variables, such as the level of production from existing wells, prices of crude oil and natural gas, and our success in finding, developing and producing new reserves. If revenues were to decrease as a result of lower crude oil and natural gas prices or decreased production, and our access to capital were limited, we would have a reduced ability to replace our reserves, resulting in a decrease in production over time. If our cash flows from operations are not sufficient to meet our obligations and fund our capital budget, we may not be able to access debt, equity or other methods of financing on an economic basis to meet these requirements, particularly in the current economic environment. If we are not able to fund our capital expenditures, interests in some properties might be reduced or forfeited as a result.

Reserve estimates depend on many interpretations and assumptions that may turn out to be inaccurate. Any significant inaccuracies in these interpretations and assumptions could cause the reported quantities and the value of our reserves to be materially misstated.

Estimating quantities of crude oil, NGLs and natural gas reserves and future net cash flows from such reserves is a complex, inexact process. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors, made by our management and our independent reserve engineering firms; Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc. Any significant inaccuracies in these interpretations or assumptions could cause the reported quantities of our reserves and future net cash flows from such reserves to be overstated or understated. Also, the data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

To prepare estimates of our economically recoverable crude oil, NGLs and natural gas reserves and future net cash flows from our reserves, we analyze many variable factors, such as historical production from the area compared with

production rates from other producing areas. We also analyze available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also involves economic assumptions relating to commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, many of which factors are or may be beyond our control.

Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this report should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on average 12-month sales prices using the average beginning-of-month price. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves.

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Discoveries or Acquisitions of reserves are needed to avoid a material decline in reserves and production.

The production rates from oil and gas properties generally decline as reserves are depleted, while related per unit production costs generally increase, due to decreasing reservoir pressures and other factors. Therefore, our estimated proved reserves and future oil, gas and NGL production will decline materially as reserves are produced unless we conduct successful exploration and development activities or, through engineering studies, identify additional producing zones in existing wells, secondary or tertiary recovery techniques, or acquire additional properties containing proved reserves. Consequently, our future oil, gas and NGL production and related per unit production costs are highly dependent upon our level of success in finding or acquiring additional reserves.

If we acquire crude oil and natural gas properties, our failure to fully identify existing and potential problems and liabilities, to accurately estimate reserves, production rates or costs, or to effectively integrate the acquired properties into our operations could materially and adversely affect our business, financial condition and results of operations.

From time to time, we seek to acquire crude oil and natural gas properties. Although we perform reviews of properties to be acquired in a manner that we believe is duly diligent and consistent with industry practices, reviews of records and properties may not necessarily reveal existing or potential problems, nor may they permit us to become sufficiently familiar with the properties in order to assess fully their deficiencies and potential. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise in the future. Even when problems with a property are identified, we often may assume environmental and other risks and liabilities in connection with acquired properties pursuant to the acquisition agreements. In addition, there are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves (as discussed further above), actual future production rates and associated costs with respect to acquired properties. Actual reserves, production rates and costs may vary substantially from those assumed in our estimates.

In addition, an acquisition may have a material and adverse effect on our business and results of operations, particularly during the periods in which the operations of the acquired properties are being integrated into our ongoing operations or if we are unable to effectively integrate the acquired properties into our ongoing operations.

Title to the properties in which we have an interest may be impaired by title defects.

We generally conduct due diligence to review title on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is due to title defects is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

There is a possibility that we will lose the leases to our oil and gas properties.

Our oil and gas revenues are generated through oil and gas leases. These leases are conditioned on the performance of certain obligations, primarily the obligation to produce oil and/or gas or engage in operations designed to result in the production of oil and gas. If production ceases and operations are not commenced within a specified time, the lease may be lost. The loss of our leases may have a material impact on our revenues.

In the case of Israeli-based properties, we have interests in licenses that, subject to certain conditions, may result in leases being granted. The leases are subject to certain obligations and are renewable at the discretion of various governmental authorities. As such, if the parties responsible for operations are not able to fulfill their obligations under the leases, the leases may be modified, cancelled, not renewed, or renewed on terms different from the current leases. The modification or cancellation of our leases could eliminate our interests and may have a material impact on

our revenues.

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We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous federal, regional, state, tribal, local, and foreign laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling and production activities;
- protection of endangered species;
- amounts and types of emissions and discharges;
- generation, management, and disposition of waste materials;
- reclamation and abandonment of wells and facility sites; and
- remediation of contaminated sites;

In addition, these laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations. Future environmental laws and regulations, such as the restriction against emission of pollutants from previously unregulated activities or the designation of previously unprotected species as threatened or endangered in areas where we operate, may negatively impact our industry. The cost of satisfying these requirements may have an adverse effect on our financial condition, results of operations, or cash flows or could result in limitations on our exploration and production activities, which could have an adverse impact on our ability to develop and produce our reserves.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;
- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- loss or damage to equipment;
- well blowouts in some cases; and
- worker's compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover claims made against us in the future.

Reduced demand for or excess capacity of production services could adversely affect our profitability.

Our profitability in the future will depend on many factors, but largely on pricing and utilization rates for our production services. An increase in supply of well servicing rigs and equipment, without a corresponding increase in demand, or decrease in demand for well servicing rigs and equipment could decrease the pricing and utilization rates of our production services, which would adversely affect our revenues and profitability.

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Competition in the oil and gas exploration and production industry is intense, and many of our competitors have greater resources than we have.

We compete with national oil companies, major integrated oil and gas companies, independent oil and gas companies and other individual producers for the acquisition of licenses and leases, properties and reserves and the equipment, materials, services and employees and other contract personnel (including geologists, geophysicists, engineers and other specialists) required to explore, develop, produce and market crude oil and natural gas. Some of our competitors may have greater and more diverse resources on which to draw than we do. As a consequence, we may be at a competitive disadvantage in certain respects, such as in bidding for drilling rights, acquisition of licenses and leases, properties and reserves or in acquiring necessary services, equipment, materials and personnel. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

Poor general economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, energy costs, geopolitical issues, the availability and cost of credit, the U.S. mortgage market, uncertainties with regard to European sovereign debt, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic conditions have had a significant adverse impact on global financial markets and commodity prices. If the economic recovery in the United States or abroad remains prolonged, demand for petroleum products could diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs, affect our vendors', suppliers' and customers' ability to continue operations, and ultimately adversely impact our results of operations, liquidity, and financial condition.

Our hedging activities may prevent us from benefiting fully from price increases and may expose us to other risks.

In order to manage our exposure to price risks in the marketing of our oil and natural gas production, we sometimes enter into oil and natural gas price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

our actual production is less than hedged volumes;

there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement; or

the counterparties to our hedging agreements fail to perform under the contracts.

a sudden unexpected event materially impacts oil and natural-gas prices.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing

obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facility is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facility. Moreover, to the extent that purchasers of the Company's production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to the Company if such purchasers were unable to access the credit or equity markets for an extended period of time.

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We have no means to market our oil and gas production without the assistance of third parties.

The marketability of our production depends upon the proximity of our reserves to, and the capacity of, facilities and third party services, including oil and natural gas gathering systems, pipelines, trucking or terminal facilities, and processing facilities. The unavailability or lack of capacity of such services and facilities could impair or delay the production of new wells or the delay or discontinuance of development plans for properties. A shut-in, delay or discontinuance could adversely affect our financial condition. In addition, regulation of oil and natural gas production transportation in the United States or in other countries may affect its ability to produce and market our oil and natural gas on a profitable basis.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

We depend on the skill, ability and decisions of third party operators to a significant extent.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our

interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

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Our operations in Israel may be adversely affected by unique economic, terrorist activities and political developments.

We have interests in oil and gas leases and in oil and gas licenses in the waters off Israel. These interests are a significant portion of our future production and cash flow and may be adversely affected by terrorist activities, political and economic developments, including the following:

war, terrorist acts and civil disturbances, and other political risks

changes in taxation policies,

laws and policies of the US and Israel affecting foreign investment, taxation, trade and business conduct,

foreign exchange restrictions,

international monetary fluctuations and changes in the value of the US dollar, such as the decline of the US dollar and

other hazards arising out of Israeli governmental sovereignty over areas in which we own oil and gas interests.

Oilfield service is a highly competitive, fragmented industry in which price competition could reduce our profitability.

We encounter substantial competition from other oilfield service companies. Our primary market areas are highly fragmented and competitive. The fact that production services equipment are mobile and can be moved from one market to another in response to market conditions heightens the competition in the industry and may result in an oversupply of equipment in an area. Oilfield service companies compete primarily on a regional basis, and the intensity of competition may vary significantly from region to region at any particular time. If demand for drilling or production services improves in a region where we operate, our competitors might respond by moving in suitable rigs and production services equipment from other regions. An influx of equipment from other regions could rapidly intensify competition, reduce profitability and make any improvement in demand for production services short-lived.

Most production services contracts are awarded on the basis of competitive bids, which also results in price competition. In addition to pricing and equipment availability, we believe the following factors are also important to our clients in determining which production services provider to select:

the type and condition of each of the competing well servicing rigs;

the quality of service and experience of the crews;

the safety record of the company providing the services; and

the offering of ancillary services;

We could be adversely affected if shortages of equipment, supplies or personnel occur.

From time to time there have been shortages of production services equipment and supplies during periods of high demand which we believe could recur. Shortages could result in increased prices for production services equipment or supplies that we may be unable to pass on to clients. In addition, during periods of shortages, the delivery times for

equipment and supplies can be substantially longer. Any significant delays in our obtaining production services equipment or supplies could limit production services operations and jeopardize our relations with clients. In addition, shortages of production services equipment or supplies could delay and adversely affect our ability to obtain new contracts for our rigs, which could have a material adverse effect on our financial condition and results of operations.

Our strategy of constructing well servicing rigs during periods of peak demand requires that we maintain an adequate supply of rig components to complete our rig building program. Our suppliers may be unable to continue providing us the needed rig components if their manufacturing sources are unable to fulfill their commitments.

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Our operations require the services of employees having the technical training and experience necessary to achieve the proper operational results. As a result, our operations depend, to a considerable extent, on the continuing availability of such personnel. Shortages of qualified personnel have occurred in our industry. If we should suffer any material loss of personnel to competitors or be unable to employ additional or replacement personnel with the requisite level of training and experience to adequately operate our equipment, our operations could be materially and adversely affected. A significant increase in the wages paid by other employers could result in a reduction in our workforce, increases in wage rates, or both. The occurrence of either of these events for a significant period of time could have a material adverse effect on our financial condition and results of operations.

We may be unable to implement price increases or maintain existing prices on our core services.

We periodically seek to increase the prices of our services to offset rising costs and to generate higher returns for our stockholders. However, we operate in a very competitive industry and as a result, we are not always successful in raising, or maintaining our existing prices. Additionally, during periods of increased market demand, a significant amount of new service capacity, including new well service rigs may enter the market, which also puts pressure on the pricing of our services and limits our ability to increase or maintain prices. Furthermore, during periods of declining pricing for our services, we may not be able to reduce our costs accordingly, which could further adversely affect our profitability.

Even when we are able to increase our prices, we may not be able to do so at a rate that is sufficient to offset such rising costs. In periods of high demand for oilfield services, a tighter labor market may result in higher labor costs. During such periods, our labor costs could increase at a greater rate than our ability to raise prices for our services. Also, we may not be able to successfully increase prices without adversely affecting our activity levels. The inability to maintain our prices or to increase our prices as costs increase could have a material adverse effect on our business, financial position and results of operations.

Member of Isramco's management team own a significant amount of common stock, giving them influence or control in corporate transactions and other matters, and the interests of these individuals could differ from those other shareholders.

Member of our management team individually and through companies they beneficially control own 67.16% of our outstanding shares of common stock as of March 9, 2014. As a result, these shareholders are in a position to significantly influence or control the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of an amendment to our certificate of incorporation or bylaws, and the approval of mergers and other significant corporate transactions.

Our stock price is volatile and could continue to be volatile and has limited liquidity; Accordingly, investors may not be able to sell any significant number of shares of our stock at prevailing market prices.

Investor interest in our common stock may not lead to the development of an active or liquid trading market. The market price of our common stock has fluctuated in the past and is likely to continue to be volatile and subject to wide fluctuations. In addition, the stock market has experienced extreme price and volume fluctuations. The stock prices and trading volumes for our stock has fluctuated widely and the average daily trading volume of our stock continues to be limited and may continue for reasons that may be unrelated to business or results of operations. General economic, market and political conditions could also materially and adversely affect the market price of our common stock and investors may be unable to resell their shares of common stock at or above their purchase price. As a result of the limited trading in our stock, it may be difficult for investors to sell their shares in the public market at any given time at prevailing prices.

We have not paid dividends on our common stock and do not plan to declare dividends in the foreseeable future, and therefore only appreciation of the price of our common stock will provide a return to our shareholders.

We have not paid or declared any dividends on our common stock and currently intend to retain any earnings to fund our working capital needs, reduce debt and fund growth opportunities. Any future dividends will be at the discretion of our board of directors after taking into account various factors it deems relevant, including our financial condition and performance, cash needs, income tax consequences and restrictions imposed by the Texas Business Organizations Code and other applicable laws

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

Oil and Gas Exploration and Production - Properties and Reserves

Reserve Information. For estimates of Isramco's net proved reserves of natural gas, crude oil and natural gas liquids, see Note 15 to Consolidated Financial Statements, Supplemental Oil and Gas Information.

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 producer. The reserve data set forth in Note 15 to Consolidated Financial Statements, Supplemental Oil and Gas Information, represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of natural gas, crude oil and condensate and natural gas liquids that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the amount and quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers normally vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate (upward or downward). Accordingly, reserve estimates are often different from the quantities ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. For related discussion, see ITEM 1A. Risk Factors.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

We previously disclosed information relating to two putative shareholder derivative petitions that were filed by individual shareholders of the Company in the District Court of Harris County, Texas. These petitions each named certain of our officers and directors as defendants. Each of these suits claims that the shareholders were damaged as a result of various breaches of fiduciary duty, self-dealing, and other wrongdoing in connection with the Restated Agreement between the Company and Goodrich Global, Ltd. (“Goodrich”) and other matters, primarily on the part of the Company’s Chairman and Chief Executive Officer, Haim Tsuff, and Jakob Maimon. Mr. Maimon is a former President and a director who resigned from all positions held with the Company on June 29, 2011.

On or about April 6, 2011, a third complaint was filed in the 295th District Court of Harris County, Texas by Yuval Ran, who claimed to be a shareholder, against certain of our officers and directors and several corporate parties controlled by Haim Tsuff. As with the prior suits, this complaint alleged various breaches of duty, self dealing and other wrongdoing in connection with the Restated Agreement between the Company and Goodrich, primarily on the part of the Company’s Chairman and Chief Executive Officer, Haim Tsuff, and Jakob Maimon. In addition, this suit alleged claims relating to other transactions between the Company and entities controlled by Haim Tsuff, including but not limited to the loan transactions between the Company and related parties, the lease and sale of a cruise ship, and the closure of the Company’s Israel branch office. The third complaint was transferred to the 55th Judicial District Court of Harris County, Texas by order signed April 20, 2011, and consolidated with the above-referenced first and second original shareholder suits by order signed May 21, 2011, into a single case, called “Lead Cause No. 2010-34535; In Re: Isramco, Inc. Shareholder Derivative Litigation; In the 55th Judicial District Court of Harris County, Texas (the “Derivative Litigation”).

We also disclosed information in our quarterly report for the three months ended September 30, 2011, relating to an additional putative shareholder derivative complaint that was filed by an individual shareholder, Yuval Lapiner, on July 7, 2011, in the Delaware Chancery Court in Wilmington, Delaware, naming certain of our officers and directors as defendants. The claims asserted in this case are essentially the same damage claims as asserted in the lawsuit filed in April 2011 and described above. The Company filed motions in the Chancery Court to Dismiss or Stay the lawsuit and, by order dated October 20, 2011, the case was dismissed. The plaintiff did not appeal. Yuval Lapiner then filed a motion to intervene in the Derivative Litigation and that motion was denied. Mr. Lapiner then filed a motion for attorney's fees that was also denied. On December 12, 2011, the court approved the terms of the mediated settlement and entered final order and judgment in the case. The Company paid plaintiff attorney's fees of \$1,000,000, replaced its bylaws, amended various committee charters, and adopted other corporate governance changes as set out in the stipulation of settlement. After the judgment was rendered, Mr. Lapiner filed a motion for new trial and on February 12, 2012, filed a Notice of Appeal to the Fourteenth Court of Appeals in Houston, Texas. A Motion to Dismiss the appeal was filed. Oral arguments were presented to the Court of Appeals on January 9, 2013. The Court of Appeals has not rendered an opinion on either the Motions to Dismiss or the appeal. We do not believe the appeal will be successful.

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On or about September 21, 2011, the Company's former Vice President and General Counsel, Dennis Holifield resigned. Mr. Holifield had been hired in March 2011. On or about October 12, 2011, Mr. Holifield submitted a "Summary Report" to the SEC (the "Summary Report"), in which made numerous factual allegations regarding Haim Tsuff, the Company's Chief Executive Officer, Chairman, and President; Edy Francis, the Company's Chief Financial Officer; Amir Sanker, the Company's Asset Manager; and other Company personnel. In the Summary Report, Mr. Holifield characterized the alleged conduct as illegal or criminal. On November 3, 2011, the Company's Board of Directors constituted a committee of independent directors consisting of Max Pridgeon and Asaf Yarkoni, referred to as the Special Investigative Committee of the Board of Directors ("SIC") which was directed to investigate all of the Holifield allegations and report back to the full board and make any recommendations, if any, for corrective action. On January 7, 2013, SIC made their final report to the Board of Directors of the conclusions and results of the fourteen-month investigation into the allegations made by Mr. Holifield. The SIC determined that Mr. Holifield's allegations were not supported by any available documentary evidence or by any statements made by former or current Isramco, Inc., directors, management, or employees interviewed by the SIC or its counsel. The SIC also determined that the Company had not engaged in wrongdoing of any sort including any unlawful or unethical business practices, any lapses in financial controls, or any governance issues that require redress or reform.

On September 10, 2013, the Company filed suit against Mr. Holifield in Cause No. 201352927 of the 270th Judicial District Court of Harris County, Texas, to collect damages owing to the Company by virtue of Mr. Holifield's actions, which are alleged in the suit to include, but are not limited to, negligence, negligence per se, gross negligence, and breach of fiduciary duty owed to the Company. In response, in December 2013, Mr. Holifield filed a pro se answer which included counterclaims and a summary judgment motion. In his counterclaims, Mr. Holifield seeks to recover from the Company the following damages, inter alia: (i) over \$2,000,000 for loss of income and failure to secure gainful employment arising from his constructive discharge or termination by the Company; (ii) over \$2,000,000 for loss of earnings due to his alleged inability to obtain gainful employment by virtue of the damage caused to his professional reputation by alleged willful and deliberate acts of Haim Tsuff, Edy Francis, and Amir Sanker, (iii) over \$2,000,000 due to the intentional infliction of emotional distress to Mr. Holifield; (iv) an amount estimated at \$5,000,000 arising from Mr. Holifield's claim that the Company violated the Racketeer Influenced Corrupt Organizations Act, by engaging in racketeering and conspiracy; (v) over \$5,000,000 arising from the Company's alleged fraudulent misrepresentation regarding Isramco's purpose in hiring Mr. Holifield and (vi) other relief. The Company believes Mr. Holifield's counter claims have no merit. The Company intends to vigorously (i) pursue its case against Mr. Holifield and (ii) defend against Mr. Holifield's counterclaims.

From time to time, we are involved in disputes and other legal actions arising in the ordinary course of business. In management's opinion, none of these other disputes and legal actions is expected to have a material impact on our consolidated financial position or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Our common stock is listed on the NASDAQ Capital Market under the symbol "ISRL". The following table sets forth for the periods indicated, the reported high and low closing prices for our common stock. As of March 3, 2014, there were approximately 211 holders of record of our common stock.

	High	Low
2013		
First Quarter	\$ 106.75	\$ 95.46
Second Quarter	102.75	85.10
Third Quarter	124.98	93.70
Fourth Quarter	150.46	93.70
2012		
First Quarter	\$ 97.84	\$ 73.55
Second Quarter	113.21	76.00
Third Quarter	120.69	94.72
Fourth Quarter	118.00	76.47

We have never paid cash dividends on our common stock. We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including other factors, as the board of directors deems relevant.

ITEM 6. SELECTED FINANCIAL DATA

Not applicable

ITEM 7. MANAGEMENT DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

THE FOLLOWING COMMENTARY SHOULD BE READ IN CONJUNCTION WITH THE CONSOLIDATED FINANCIAL STATEMENTS AND RELATED NOTES CONTAINED ELSEWHERE IN THIS FORM 10-K. THE DISCUSSION CONTAINS FORWARD-LOOKING STATEMENTS THAT INVOLVE RISKS AND UNCERTAINTIES. THESE STATEMENTS RELATE TO FUTURE EVENTS OR OUR FUTURE FINANCIAL PERFORMANCE. IN SOME CASES, YOU CAN IDENTIFY THESE FORWARD-LOOKING STATEMENTS BY TERMINOLOGY SUCH AS "MAY," "WILL," "SHOULD," "EXPECT," "PLAN," "ANTICIPATE," "BELIEVE," "ESTIMATE," "PREDICT," "POTENTIAL," "INTEND," OR "CONTINUE," AND SIMILAR EXPRESSIONS. THESE STATEMENTS ARE ONLY PREDICTIONS. OUR ACTUAL RESULTS MAY DIFFER MATERIALLY FROM THOSE ANTICIPATED IN THESE FORWARD-LOOKING STATEMENTS AS A RESULT OF A VARIETY OF FACTORS, INCLUDING, BUT NOT LIMITED TO, THOSE SET FORTH UNDER "RISK FACTORS" AND ELSEWHERE IN THIS FORM 10-K.

Overview

We are an independent oil and natural gas company engaged in the exploration, development, and production of oil and natural gas properties located onshore in the United States and an owner of various royalty interests offshore Israel. Our properties are primarily located in Texas, New Mexico and Oklahoma. We act as the operator of most of our U.S. properties. Historically, we have grown through acquisitions, with a focus on properties within our core operating areas that we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves while lowering lease operating costs. In August, 2011 we created a new well service subsidiary that began operations in October 2011. As of December 2013, the subsidiary had 27 deployed well service rigs that operate primarily in Texas and New Mexico. The company provides a full range of well services such as well completion and wellbore maintenance, workover, plugging and abandonment services.

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We own an overriding royalty interest of 1.5375% in the Tamar Field, which will increase to 2.7375% after payout (collectively the “Tamar Royalty”). An overriding royalty interest is an ownership interest in the oil and gas leasehold estate equating to a certain percentage of production or production revenues, calculated free of the costs of production and development of the underlying lease(s), but subject to its proportionate share of certain post production costs. An overriding royalty interest is a non-possessory interest in the oil and gas leasehold estate and, accordingly, we have no control over the operations, drilling, expenses, timing, production, sales, or any other aspect of development or production of the Tamar Field.

The Tamar project began production in March 2013 and is now fully operational and delivering significant volumes of natural gas to Israel.

Oil and Gas Exploration and Production Segment

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire additional properties with existing production. The amount we realize for our production depends predominantly upon commodity prices, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, quality, basis differentials and other factors, and secondarily upon our commodity price hedging activities. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success. Our future drilling plans are subject to change based upon various factors, some of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. To the extent these factors lead to reductions in our drilling plans and associated capital budgets in future periods, our financial position, cash flows and operating results could be adversely impacted.

We own an overriding royalty interest of 1.5375% in the Tamar Field, which will increase to 2.7375% after payout (collectively the “Tamar Royalty”). An overriding royalty interest is an ownership interest in the oil and gas leasehold estate equating to a certain percentage of production or production revenues, calculated free of the costs of production and development of the underlying lease(s), but subject to its proportionate share of certain post production costs. An overriding royalty interest is a non-possessory interest in the oil and gas leasehold estate and, accordingly,, we have no control over the operations, drilling, expenses, timing, production, sales, or any other aspect of development or production of the Tamar Field.

The Tamar project began production in March 2013 and is now operational and delivering significant volumes of natural gas to Israel. The natural gas flows from the Tamar field through the world's longest subsea tieback, more than 90 miles to the Tamar platform, and then to the Ashdod onshore terminal.

During year ended December 31, 2013, net sales from the Tamar Field attributable to Isramco amounted to 2,736,000 Mcf of natural gas and 3,788 Bbl of condensate with prices of \$5.69 per Mcf and \$99.79 per Bbl of condensate. Total revenues net of marketing and transportation expenses were \$15,824,000. The Israeli Tax Authority withheld \$3,956,000, of this revenue which is recognized as an asset on the Company’s balance sheet.

At December 31, 2013, our estimated total proved oil, natural gas reserves and natural gas liquids, as prepared by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc. and Cawley, Gillespie & Associates, Inc., were approximately 41,035 thousand barrels of oil equivalent (“MBOE”), consisting of 2,874 thousand barrels (MBbls) of oil, 218,990 million cubic feet (MMcf) of natural gas and 1,662 thousand barrels (MBbls) of natural gas liquids. Approximately 86.1% of our proved reserves were classified as proved developed (See Note 15 Supplemental

Oil and Gas Information to Consolidated Financial Statements to our consolidated financial statements). Full year 2013 production averaged 3.1 MBOE/d compared to 2.17 MBOE/d in 2012. Tamar Field production share amounted to 1.26 MBOE/d out of total 3.1 MBOE/d compared to 0 MBOE/d in 2012.

Production Services Segment

The production service market is highly competitive. Competition is influenced by such factors as price, capacity, availability of work crews, and reputation and experience of the service provider. We believe that an important competitive factor in establishing and maintaining long-term customer relationships is having an experienced, skilled and well-trained work force. We believe many of our larger customers place increased emphasis on the safety, performance and quality of the crews, equipment and services provided by their contractors. Although we believe customers consider all of these factors, price is often the primary factor in determining which service provider is awarded the work. However, in numerous instances, we secure and maintain work from large customers for which efficiency, safety, technology, size of fleet and availability of other services are of equal importance to price.

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The demand for our services fluctuates, primarily in relation to the price (or anticipated price) of oil and natural gas, which, in turn, is driven primarily by the supply of, and demand for, oil and natural gas. Generally, as supply of those commodities decreases and demand increases, service and maintenance requirements increase as oil and natural gas producers attempt to maximize the productivity of their wells in a higher priced environment. However, in a lower oil and natural gas price environment, demand for service and maintenance generally decreases as oil and natural gas producers decrease their activity. In particular, the demand for new or existing field drilling and completion work is driven by available investment capital for such work. Oil and natural gas producers generally tend to be less risk tolerant when commodity prices are low or volatile, we may experience a more rapid decline in demand for well maintenance services compared with demand for other types of oilfield services. Further, in a low commodity price environment, fewer well service rigs are needed for completions, as these activities are generally associated with drilling activity. The plugging and abandonment work is less affected by prices and generally driven by state regulations and have smaller variations in demand.

The level of our revenues, earnings and cash flows are substantially dependent upon, and affected by, the level of U.S. oil and natural gas exploration, development and production activity, as well as the equipment capacity in any particular region.

Critical accounting policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the most significant estimates and assumptions we make in applying these policies.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available - successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical, while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and a 10% discount rate. We account for our natural gas and crude oil exploration and production activities under the successful efforts method of accounting.

Proved Oil and Natural Gas Reserves

Isramco estimates its proved oil and gas reserves as defined by the SEC and the FASB. This definition includes crude oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc., i.e., at prices and costs as of the date the estimates are made. Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based upon expected future conditions.

The Company's estimates of proved reserves are made using available geological and reservoir data, as well as production performance data. These estimates are reviewed annually by our independent reserve engineering firm, Cawley, Gillespie & Associates, Inc and Netherland, Sewell & Associates, Inc. and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, reservoir performance, prices, economic conditions, and governmental restrictions, as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits earlier. A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property impairments.

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Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it non-economic to drill for and produce higher cost reserves.

Our well service equipment and tools are carried at cost less accumulated depreciation. Depreciation is provided for our assets over the estimated depreciable lives of the assets using the straight-line method. We depreciate our operational assets over their depreciable lives to their salvage value, which is a fair value higher than the assets' value as scrap. When we scrap an asset, we accelerate the depreciation of the asset down to its salvage value. When we dispose of an asset, a gain or loss is recognized.

Impairment

We review our property and equipment in accordance with Accounting Standards Codification (ASC) 360, Property, Plant, and Equipment (ASC 360). ASC 360 requires us to evaluate property and equipment as an event occurs or circumstances change that would more likely than not reduce the fair value of the property and equipment below the carrying amount. If the carrying amount of property and equipment is not recoverable from its undiscounted cash flows, then we would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, we evaluate the remaining useful lives of property and equipment at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and gas wells and to restore land at the end of oil and gas production operations. Our removal and restoration obligations are most often associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations we have will be take effect in the future. Additionally, these operations are subject to private contracts and government regulations that often have vague descriptions of what is required. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate removal cost amounts, inflation factors, credit adjusted discount rates, timing of obligations and changes in the legal, regulatory, environmental and political environments.

Accounting for Derivative Instruments and Hedging Activities

We utilized derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We may generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next years. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to our derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the consolidated statements of operations. We carry our derivatives at fair value on our consolidated balance sheets, with the changes in the fair value included in our consolidated statements of operations in the period in which the change occurs. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

Environmental Obligations, Litigation and Other Contingencies

Management makes judgments and estimates in accordance with applicable accounting rules when it establishes reserves for environmental remediation, litigation, and other contingent matters. Provisions for such matters are charged to expense when it is probable that a liability is incurred and reasonable estimates of the liability can be made. Estimates of environmental liabilities are based on a variety of matters, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental-remediation costs, such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment, and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures related to environmental or other contingent matters and actual costs may vary significantly from the Company's estimates. The Company's in-house legal counsel regularly assesses these contingent liabilities and, in certain circumstances, consults with third-party legal counsel or consultants to assist in forming the Company's conclusion.

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Income Taxes

The Company follows ASC 740, Income Taxes, (ASC 740), which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax assets and liabilities are computed using the liability method based on the differences between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

A valuation allowance is provided, if necessary, to reserve the amount of net operating loss and net deferred tax assets which the Company may not be able to use because of the expiration of maximum carryover periods allowed under applicable tax codes.

Liquidity and Capital Resources

Our primary source of liquidity was cash flow generated from our operating activities. We continuously monitor our liquidity and evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources and drilling success.

Note 5 to our Consolidated Financial Statements, Long-Term Debt and Interest Expense, describes the Senior Credit Agreements and Related Party Loans. Our Senior Credit Agreements originally provided a total \$300 million in credit facilities under a credit facility from a group of lenders, under which Wells Fargo was the lead bank (the “Lenders”). The borrowing base under the facility was redetermined on a semi-annual basis and adjusted based on our oil and natural gas properties, reserves, other indebtedness and other relevant factors. During the fourth quarter of 2011 the Lenders reduced the borrowing base to zero. On April 27, 2012, The Company entered into an amendment to the Credit Agreement with Lenders, formalizing the election to pay the \$20,000,000 borrowing base deficiency in six monthly installments of \$3,333,333.33. As of June 29, 2012 the Company has fully paid all amounts owed and terminated the Senior Credit Facility with the Lenders.

The Company is in negotiations for a commercial loan from a financial institution to obtain a new financing on terms more favorable to the Company. The Company hopes to obtain a new commercial loan that would replace its existing financing from affiliated parties and also provide additional liquidity for the Company’s operations and investments. The Company is uncertain as to whether it will be successful in obtaining a new commercial loan or, if it is obtained, there is uncertainty as to the timetable upon which such loan will be closed and other material terms and conditions. The Company believes that the current source of its affiliate financing will remain flexible and additional funding will be made available if needed until a new commercial loan can be obtained. See Note 5 to Consolidated Financial Statements, Long-Term Debt and Interest Expense.

Our future capital resources and liquidity may depend, in part, on our success in developing our existing leasehold interests and from streamlining operations of our well service operations. Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and gas industry. Future success in increasing reserves and production will be highly dependent on capital resources available and the success in finding and acquiring additional reserves. We expect to fund our future capital requirements through internally generated cash flows and, possibly, a new commercial loan from a third party lender.

Long-term cash flows are subject to a number of variables, including the level of production and prices as well as various economic conditions that have historically affected the oil and natural gas industry. Our well service business requires capital to fund ongoing operations, including maintenance expenditures on our existing fleet and equipment, organic growth initiatives, and investments in new equipment and tools. We plan to fund these activities from Isramco’s available operating cash flows and possibly a commercial loan from financial institution. (See Item 1A “Risk

Factors”).

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Debt

	2013	As of December 31,	
		2012	2011
	(In thousands except percentage)		
Senior Credit Facilities	\$ -	\$ -	\$ -
Long – term debt – related party (1)	94,657	73,906	60,211
Short – term debt – related party (1)	-	-	6,456
Current maturities of long-term debt, short-term debt and bank overdraft	1,392	18,184	32,009
Total debt	96,049	92,090	98,676
Stockholders' equity	12,491	18,815	18,548
Debt to capital ratio	88%	83%	84%

(1) The amounts are excluded of accrued interest.

At year-end 2013, our total debt was \$96,049,000, compared to total debt of \$92,090,000 at year-end 2012 and \$98,676,000 at year-end 2011. As of December 31, 2011, current debt included \$20,000,000 as current maturities of the Senior Credit Facilities. During the fourth quarter of 2011 the Lenders reduced the borrowing base to zero. As of June 29, 2012 the Company has fully paid all amounts owed the Lenders under the terminated the Senior Credit Facility.

On March 3, 2011, the Company entered into a Loan Agreement with IOC - Israel Oil Company, Ltd. (“IOC”) pursuant to which it borrowed the sum of \$11,000,000. The loan bears interest at a rate of 10% per annum and is payable in quarterly payments of interest only until March 3, 2013, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty. The loan is unsecured. During September 2011, Isramco paid \$4,544,000 of principal pursuant to this Loan agreement with IOC.

In October 2011 the agreement with IOC, pertaining to a loan in the outstanding principal amount of \$6,456,000 was renegotiated. The payoff of principal amount was extended by 6 month to September 9, 2013. Interest accrued per annum was determined on LIBOR+5.5% from initial 10%.

On March 29, 2012, the Company entered into a Loan Agreement with IOC pursuant to which it borrowed \$3,500,000. The loan bears interest at a rate of Libor + 5.5% per annum and matures on March 29, 2013, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty or premium. The loan is unsecured.

On April 29, 2012, the Company entered into another Loan Agreement with IOC, pursuant to which it borrowed \$10,000,000. The loan bears interest of Libor+5.5% per annum and matures on April 30, 2013, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty or premium. The loan was funded by IOC in three monthly installments starting April 2012. The loan is unsecured. The purpose of the loan was to provide funds to Isramco for the payment of amounts that were due to the Lenders under the Senior Credit Facility that was paid in full June 29, 2012.

On February 13, 2013, the Company entered into another Loan Agreement with IOC, pursuant to which it borrowed \$1,500,000. The loan bears interest of Libor+6% per annum and matures on February 13, 2018, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty or premium. The loan is unsecured. The purpose of the loan was to provide funds to back up a Letter of Credit.

On March 1, 2013, all of the above-mentioned Loan agreements and notes with IOC except for the \$1,500,000 loan agreement entered on February 13, 2013, were amended. The terms of all these loans and notes between the Company and IOC were amended extending the maturity to December 31, 2018. In addition the payment schedule was changed on the all of the loans and notes to require accrued interest only payments December 31, 2014, December 31, 2015, December 31, 2016, December 31, 2017 and final interest payment December 31, 2018 with outstanding principal paid in four equal installments with the first payment December 31, 2015 and a similar payment made December 31 in each of the following three years until the final payment on December 31, 2018. The other terms of the loan agreements and notes remained unchanged. In accordance with the amendment, as of December 31, 2013 the loans are classified as long-term on our consolidated balance sheets.

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On March 1, 2013, the terms of existing loan and note between the Company and Naptha Israel Petroleum Corp., LTD., a related party (“Naphtha”) were also amended extending the maturity to December 31, 2018. The payment schedule was changed on the Naphtha loan and note to require interest only payments December 31, 2013, December 31, 2014, December 31, 2015, December 31, 2016, December 31, 2017 and the final interest payment December 31, 2018 with principal outstanding paid in four equal installments with the first payment December 31, 2015 and a similar payment made December 31 in each of the following three years until the final payment on December 31, 2018. The other terms of the loan agreement and note remained unchanged. In accordance with the amendment, as of December 31, 2013 the loan is classified as long-term on our balance sheet.

On June 30, 2013, the terms of an Amended and Restated Loan Agreement dated May 25, 2008, and note between the Company and Jerusalem Oil Exploration, Ltd. (“JOEL”) were amended to extend the maturity date to June 30, 2017. The payment schedule of the loan agreement and note was amended to require principal and accrued interest to be paid in three installments in the amounts reflected in Promissory Note due on June 30th of each year commencing June 30, 2015. The other terms of the loan agreement and note remained unchanged. In accordance with the amendment, as of December 31, 2013, the loan is classified as long-term on our consolidated balance sheets.

Off-Balance Sheet Arrangements

At December 31, 2013, we did not have any off-balance sheet arrangements.

Cash Flow

Our primary source of cash in 2013 was cash flow from operating activities. In 2013, cash received from operations and was primarily used for investments in equipment for our well service subsidiary, oil and gas properties and restricted cash deposit.

In 2012 cash received from operations, sale of marketable securities and proceeds from related party were used primarily to repay borrowings under our Senior Credit Facility and investing in equipment for well service subsidiary. Our primary source of cash in 2011 was cash flow from operating activities, loans from related parties and proceeds from sale of investment in MediaMind Ltd shares. In 2011 cash received from operations, from selling of investment in MediaMind Ltd shares and from related parties was offset by repayments of borrowings under our Senior Credit Agreements, repayment of related party loans, purchase of equipment and payments made on settled derivatives contracts.

Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in commodity prices and our overall cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal fluctuations characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. See Results of Operations below for a review of the impact of prices and volumes on sales.

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows provided by operating activities	\$ 24,282	\$ 17,000	\$ 6,946
Cash flows provided by (used in) investing activities	(21,931)	(12,031)	7,643
	1,183	(6,476)	(18,124)

Cash flows provided
by (used in) financing
activities

Net increase (decrease) in cash	\$	3,534	\$	(1,507)	\$	(3,535)
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Operating Activities, Net cash flows provided by operating activities were \$24,282,000, \$17,000,000 and \$6,946,000 for the years ended December 31, 2013, 2012 and 2011, respectively. Key drivers of net operating cash flows are commodity prices, production volumes, operating costs, proceeds from an overriding royalty interest in the Tamar Field and activities of our well service subsidiary in the year ended December 31, 2013.

During the year ended December 31, 2013, compared to the same period in 2012, net cash flow provided by operating activities increased by \$7,282,000 to \$23,346,000. The increase was primarily attributable to proceeds from our overriding royalty in Tamar Field off shore Israel and revenues from our well service segment. This increase was partially offset by changes in the working capital, and cash received on settlement of derivative contracts in 2012 with no corresponding transaction in 2013, and decrease in crude oil, natural gas and natural gas liquids (“NGLs”) revenues. The decrease in revenues from crude oil, natural gas and NGLs was caused by a decrease in production volumes of crude oil, natural gas and NGLs and a decrease in sale prices of NGLs which were slightly offset by increase in sale prices of crude oil and natural gas. The average crude oil prices for the twelve months ended December 31, 2013 were \$95.71/Bbl, compared to \$92.75/Bbl, natural gas \$3.97/Mcf, compared to \$3.68/Mcf and natural gas liquids average prices of \$31.85/Bbl, compared to \$36.19/ Bbl in the corresponding period in 2012.

During the year ended December 31, 2012, compared to the same period in 2011, net cash flow provided by operating activities increased by \$10,054,000 to \$17,000,000 This increase was primarily attributable to a net cash onetime payment in 2011 on settled derivatives contracts of \$7,007,000, activities of our well service subsidiary and lower lease operating expenses which were partially offset by payment a portion of accrued interest on the loan to related party of \$2,000,000 and decrease in NGLs revenues. The decrease in natural gas and NGLs revenues was caused by both decrease in natural gas and NGLs prices and as well as decrease in production volumes of natural gas and NGLs. The decrease in revenues was primarily attributable to lower average gas prices for the twelve months ended December 31, 2012 of \$3.68/Mcf, compared to \$4.97/Mcf and natural gas liquids average prices for the twelve months ended December 31, 2012 of \$36.19/Bbl, compared to \$50.24/ Bbl to the corresponding period in 2011.

However, we are unable to predict future production levels, future commodity prices, future proceeds from our Tamar Field royalties, and future revenues generated by our well service segment; therefore, we cannot predict future levels of net cash provided by operating activities.

Investing Activities, Net cash flows used in investing activities for the twelve months ended December 31, 2013 and 2012 were \$21,931,000 and \$12,031,000, respectively. During 2013 the Company invested in equipment and oil and gas properties amount of \$16,459,000 and \$4,019,000 respectively and increased restricted cash balance by \$1,500,000.

Net cash flows provided (used) in investing activities for the twelve months ended December 31, 2012 and 2011 were \$(12,031,000) and \$7,643,000, respectively. During 2012, the Company invested in equipment for its well service subsidiary and oil and gas properties amount of \$11,575,000 and \$5,422,000 respectively. These investments of \$16,997,000 were partially offset by proceeds from sale of investment in marketable securities in the amount of \$4,737,000.

The primary driver of cash provided by investing activities in 2011 was proceeds from sale of marketable securities of \$16,073,000 which was offset by purchase of other property and equipment of approximately \$6,500,000 and an additional \$2,549,000 spent on capital expenditures.

Financing Activities, Net cash flows provided by (used in) financing activities were \$1,183,000 and (\$6,476,000) for the year ended December 31, 2013 and 2012, respectively. In 2013 the Company received a loan from a related party in the amount of \$1,500,000, made payments related to its short term debt of \$335,000 and increased its bank overdraft by \$18,000.

Net cash flows used in financing activities for the twelve months ended December 31, 2012 and 2011 were \$6,476,000 and \$18,124,000 respectively. The Company has fully repaid the outstanding debt under Senior Credit Facility in the amount of \$20,000,000 which was partially offset by new borrowings of \$13,500,000 from a related party.

During the year ended in 2011, we repaid borrowings of \$29,612,000.

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Results of Continuing Operations

	Selected Data		
	Years Ended December 31,		
	2013	2012	2011
(In thousands except per share and MBOE amounts)			
Financial Results			
Oil and Gas sales			
United States	\$ 35,464	\$ 40,402	\$ 44,228
Non-U.S.	15,824	-	-
Production Services	16,294	9,279	896
Other	1,110	749	524
Total revenues and other	68,692	50,430	45,648
Cost and expenses	72,021	44,433	41,278
Other expense (income)	6,611	2,455	(6,991)
Income tax expense (benefit)	(3,616)	1,095	3,975
Net income (loss) attributable to common shareholders	(6,324)	2,447	7,386
Net income attributable to noncontrolling interests	386	226	5
Net income (loss) attributable to Isramco	(6,710)	2,221	7,381
Earnings (loss) per common share – basic	\$ (2.47)	\$ 0.82	\$ 2.72
Earnings (loss) per common share –diluted	\$ (2.47)	\$ 0.82	\$ 2.72
Weighted average number of shares outstanding-basic	2,717,691	2,717,691	2,717,691
Weighted average number of shares outstanding- diluted	2,717,691	2,717,691	2,717,691
Operating Results			
Adjusted EBITDAX (1)	\$ 32,833	\$ 25,713	\$ 30,606
Total proved reserves (MBOE)	41,035	36,266	34,990
Sales volumes United States (MBOE)	672	791	789
Sales volumes Non-U.S. (MBOE)	460	-	-

Average cost per BOE - United States:						
Production (excluding transportation and taxes)	\$	23.87	\$	19.12	\$	20.55
General and administrative	\$	7.05	\$	5.70	\$	5.63
Depletion of oil and gas properties	\$	15.88	\$	13.45	\$	12.55

- (1) See Adjusted EBITDAX for a description of Adjusted EBITDAX, which is not a Generally Accepted Accounting Principles (GAAP) measure, and a reconciliation of Adjusted EBITDAX to income from operations before income taxes, which is presented in accordance with GAAP.

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Financial Results

Net Income, our net loss was \$(6,710,000), or \$(2.47) per share for the year ended December 31, 2013. This compares to net income of \$2,221,000, or \$0.82 per share, for the year ended December 31, 2012.

This decrease was primarily due to a one time impairment of \$23,161,000 on our oil and gas properties in United States, the Company's net gain of \$3,650,000 on sale of our investment in shares of Jerusalem Oil Exploration Ltd, ("JOEL") a related party and a net gain of \$219,000 on derivative contracts in 2012 (with no corresponding gains in 2013), lower crude oil, natural gas and NGLs sales revenues in 2013 as a result of a decrease in crude oil, natural gas and NGLs sales volumes, and a decrease in NGLs prices. This decrease was partially offset by revenues from overriding royalty in Tamar Field off shore Israel and increase in revenues from well service activities.

In 2012 our net income was \$2,221,000, or \$0.82 per share. This compares to net income of \$7,381,000 or \$2.72 per share, for the year ended December 31, 2011.

This decrease was primarily due to a net gain of \$3,650,000 on sale of our investment in shares of Jerusalem Oil Exploration Ltd, ("JOEL") a related party in 2012 comparing to a net gain on the sale of shares of Media Mind in 2011 in the amount of \$15,910,000, lower natural gas and NGLs sales revenues as a result of the decrease in natural gas and NGLs prices and decrease in production volumes of natural gas and NGLs all of which were partially offset by increase in revenues from well service activities, a net gain on derivative contracts lower tax and interest expenses comparing to twelve months ended December 31, 2011.

Revenues, Volumes and Average Prices – United States

Sales Revenues

	Years Ended December 31,		Dvs. 2012	2011	D vs. 2011
	2013	2012			
Gas sales	\$ 7,139	\$ 7,950	(10)%	\$ 11,135	(29)%
Oil sales	24,694	27,639	(11)	26,260	5
Natural gas liquid sales	3,631	4,813	(25)	6,833	(30)
Total	\$ 35,464	\$ 40,402	(12)%	\$ 44,228	(9)%

Our sales revenues for the year ended December 31, 2013 decreased by 12% when compared to the same period of 2012, mainly due to decreased production volumes for crude oil, natural gas and natural gas liquids and lower NGLs prices. This decrease was partially offset by higher prices for crude oil and natural gas. Our sales revenues for the year ended December 31, 2012 decreased by 9% when compared to the same period of 2011, mainly due to lower prices received for natural gas and condensate and NGLs and decreased production volumes for natural gas and natural gas liquids which was partially offset by increase in crude oil revenues.

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Volumes and Average Prices

	Years Ended December 31,				
	2013	2012	D vs. 2012	2011	D vs. 2011
Natural Gas					
Sales volumes Mmcf	1,798	2,160	(17)%	2,241	(4)%
Price per Mcf (1)	\$ 3.97	\$ 3.68	8	\$ 4.97	(26)
Total gas sales revenues (thousands)	\$ 7,139	\$ 7,950	(10)%	\$ 11,135	(29)%
Crude Oil					
Sales volumes MBbl	258	298	(13)%	279	7%
Price per Bbl (1)	\$ 95.71	\$ 92.75	3	\$ 94.12	(1)
Total oil sales revenues (thousands)	\$ 24,694	\$ 27,639	(11)%	\$ 26,260	5%
Natural gas liquids					
Sales volumes MBbl	114	133	(14)%	136	(2)%
Price per Bbl (1)	\$ 31.85	\$ 36.19	(12)	\$ 50.24	(28)
Total natural gas liquids sales revenues (thousands)	\$ 3,631	\$ 4,813	(25)%	\$ 6,833	(30)%

(1) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

The company's natural gas sales volumes decreased by 17%, crude oil sales volumes decreased by 13% and natural gas liquids sales volumes decreased by 14% for the year ended December 31, 2013 compared to the same period of 2012.

Our average natural gas price for the year ended December 31, 2013 increased by 8%, or \$0.29 per Mcf, when compared to the same period of 2012. Our average crude oil price for the year ended December 31, 2013 increased by 3%, or \$2.96 per Bbl, when compared to the same period of 2013. Our average natural gas liquids price for the year ended December 31, 2013 decreased by 12%, or \$4.34 per Bbl, when compared to the same period of 2012.

In 2011 the company's natural gas sales volumes decreased by 4%, crude oil sales volumes increased by 7% and natural gas liquids sales volumes decreased by 2% for the year ended December 31, 2012 compared to the same period of 2011.

Analysis of Oil and Gas Operations Sales Revenues

The following table provides a summary of the effects of changes in volumes and prices on Isramco's sales revenues for the year ended December 31, 2013 compared to 2012 and 2011.

In thousands	Natural Gas	Oil	Natural gas liquids
2011 sales revenues	11,135	26,260	6,833
Changes associated with sales volumes	(402)	1,788	(151)

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Changes in prices	(2,783)	(409)	(1,869)
2012 sales revenues	\$ 7,950	\$ 27,639	\$ 4,813
Changes associated with sales volumes	(1,332)	(3,710)	(688)
Changes in prices	521	765	(494)
2013 sales revenues	\$ 7,139	\$ 24,694	\$ 3,631

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Adjusted EBITDAX.

To assess the operating results of Isramco, management analyzes income from operations before income taxes, interest expense, exploration expense, unrealized gain (loss) on derivative contracts and DD&A expense and impairments (“Adjusted EBITDAX”). Adjusted EBITDAX is not a GAAP measure. Isramco’s definition of Adjusted EBITDAX excludes exploration expense because exploration expense is not an indicator of operating efficiency for a given reporting period, but rather is monitored by management as a part of the costs incurred in exploration and development activities. Similarly, Isramco excludes DD&A expense and impairments from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. The Company’s definition of Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Isramco’s financing methods or capital structure. Adjusted EBITDAX is a widely accepted financial indicator of a company’s ability to incur and service debt, fund capital expenditures and make payments on its long term loans. Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company’s financial condition and results of operations.

However, Adjusted EBITDAX, as defined by Isramco, may not be comparable to similarly titled measures used by other companies. Therefore, Isramco’s consolidated Adjusted EBITDAX should be considered in conjunction with income (loss) from operations and other performance measures prepared in accordance with GAAP, such as operating income or cash flow from operating activities. Adjusted EBITDAX has important limitations as an analytical tool because it excludes certain items that affect income from continuing operations and net cash provided by operating activities. Adjusted EBITDAX should not be considered in isolation or as a substitute for an analysis of Isramco’s results as reported under GAAP. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) from operations before income taxes.

In thousands	Years Ended December 31,		
	2013	2012	2011
Income (loss) from operations before income taxes (1)	\$ (9,940)	\$ 3,542	\$ 11,361
Depreciation, depletion, amortization and impairment expense	35,348	12,575	14,016
Interest expense	6,528	6,339	7,760
Gain (loss) on derivative contract	-	2,382	(3,384)
Accretion Expenses	902	875	853
Consolidated Adjusted EBITDAX	\$ 32,838	\$ 25,713	\$ 30,606

- (1) Including net gain from sale of investment in shares of JOEL in the amount of \$3,650,000 and shares of Media Mind in the amount of \$15,910,000 in 2012 and 2011 respectively.

Operating Expenses

In thousands except percentages	Years Ended December 31,				
	2013	2012	D vs. 2012	2011	D vs. 2011
Lease operating expense, transportation and taxes	\$ 19,974	\$ 19,737	1%	\$ 20,981	(6)%
Production Services	10,837	6,427	69	675	852
Depreciation, depletion and amortization oil and gas segment	10,666	10,638	NM	9,894	8
Well service equipment depreciation	1,521	712	114	88	709
Impairments of oil and gas assets	23,161	1,225	1,791	4,034	(70)
Accretion expense	902	875	3	853	3

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Loss from plug and abandonment	226	314	(28)	315	NM
General and administrative	4,734	4,505	5	4,438	2
	\$ 72,021	\$ 44,433	62%	\$ 41,278	8 %

NM – Not Meaningful

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During 2013, our operating expenses increased by 62% when compared to 2012 with the highlights as follows:

Lease operating expense, transportation cost and taxes increased by 1%, or \$237,000 in 2013 when compared to 2012. On a per unit basis, lease operating expenses (excluding transportation and taxes) increased by \$4.76 per MBOE to \$23.87 per MBOE in 2013 from \$19.12 per MBOE in 2012.

The expenses for production services pertain to our well service activities performed by well service subsidiary. Production services increased by \$4,410,000 or 69% in 2013 compared to 2012 due to expansion of the well service operations following purchase of additional workover rigs, auxiliary equipment and hire new personnel.

Depreciation, Depletion & Amortization (DD&A) of the cost of proved oil and gas properties is calculated using the unit-of-production method. Our DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact our composite DD&A rate and expense, including but not limited to field production profiles, drilling or acquisition of new wells, disposition of existing wells, and reserve revisions (upward or downward) primarily related to well performance and commodity prices, and impairments. Changes in these factors may cause our composite DD&A rate and expense to fluctuate from period to period. DD&A did not change significantly in 2013 when compared to 2012. On a per unit basis, depletion expenses increased by \$2.43 per MBOE to \$15.88 per MBOE in 2013 from \$13.45 per MBOE in 2012 due to a decrease in production volumes.

Well service equipment depreciation – the amounts represents depreciation of well service rigs and auxiliary equipment for our well service subsidiary, the increase in depreciation expenses in 2013 of \$809,000 associated with increase in the number of workover rigs and auxiliary equipment.

Impairments of oil and gas assets of \$23,161,000 in 2013 were a result of both lower estimated future crude oil, natural gas and NGLs prices which are basis for an impairment calculation and a decrease in production volumes in 2013.

Loss from plugging and abandonment expenses decreased by 28%, or \$88,000 in 2013 when compared to 2012, primarily due to less complicacy involved in our plug and abandonment operations.

General and administrative expenses increased by 5%, or \$229,000 in 2013 when compared to 2012 primarily due to higher payroll and professional services expenses.

During 2012, our operating expenses increased by 8% when compared to 2011 with the highlights as follows:

Lease operating expense, transportation cost and taxes decreased by 6%, or \$1,244,000 in 2012 when compared to 2011. This decrease was the result of reduced number of workovers on our operated properties during the twelve months ended December 2012 comparing to the same period in 2011. On a per unit basis, lease operating expenses (excluding transportation and taxes) decreased by \$1.43 per MBOE to \$19.12 per MBOE in 2012 from \$20.55 per MBOE in 2011.

Depreciation, Depletion & Amortization (DD&A) of the cost of proved oil and gas properties is calculated using the unit-of-production method. Our DD&A rate and expense are the composite of numerous individual field calculations. There are several factors that can impact our composite

DD&A rate and expense, including but not limited to field production profiles, drilling or acquisition of new wells, disposition of existing wells, and reserve revisions (upward or downward) primarily related to well performance and commodity prices, and impairments. Changes in these factors may cause our composite DD&A rate and expense to fluctuate from period to period. DD&A increased by 8%, or \$744,000, in 2012 when compared to 2011, primarily due to change in estimation of our total reserves (per MBOE) combined with addition of new drilled wells in 2012, which was partially offset by impairment recorded in 2011 in the amount of \$4,034,000. On a per unit basis, depletion expense increased by \$0.9 per MBOE to \$13.45 per MBOE in 2012 from \$12.55 per MBOE in 2011.

Well service equipment depreciation – the amount represents depreciation of well service rigs and auxiliary equipment for our well service subsidiary.

Impairments of oil and gas assets of \$1,225,000 in 2012 were primarily a result of lower natural gas prices in general and the low volume of gas produced in a few of our fields.

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Other expenses (income)

In thousands except percentages	Years Ended December 31,				
	2013	2012	D vs. 2012	2011	D vs. 2011
Interest expense net	\$ 6,528	\$ 6,339	3%	\$ 7,760	(18)%
Capital loss	83	-	100	-	-
Realized gain on sale of investment and other	-	(3,650)	(100)	(15,910)	(77)
Net loss (gain) on derivative contracts	-	(219)	(100)	922	124
Currency exchange rate differences	-	(15)	(100)	237	106
	\$ 6,611	\$ 2,455	169%	\$ (6,991)	(135)%

Interest expense. Isramco's interest expense slightly increased by 3%, or \$189,000, for the twelve months ended December 31, 2013 compared to the same period of 2012. This increase was primarily due to higher average outstanding balances of the loans during the twelve months ended December 31, 2013.

Isramco's interest expense decreased by 18%, or \$1,421,000, for the twelve months ended December 31, 2012 compared to the same period of 2011. This decrease was primarily due to onetime expense paid to Macquarie Bank, N.A in 2011 in connection with assignment and transfer of Wells Fargo Senior Credit Facility and the lower average outstanding balances of the loans during the twelve months ended December 31, 2012.

Sale of Marketable Securities. In August 2011 the company sold all of its investment in a company called MediaMind Ltd. The realized gain from this transaction amounted to \$15,910,000. On February 2012 the Company has sold all of its investment in shares of JOEL to Equital Ltd. Both JOEL and Equital Ltd. are related parties of Isramco Inc. JOEL is also a subsidiary of Equital Ltd. The Company recorded a net gain of \$3,650,000.

Net loss (gain) on derivative contracts. We may enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. In prior years, we elected not to designate any positions as cash flow hedges for accounting purposes. Accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statement of operations.

On August 15, 2012, pursuant to an agreement with Macquarie Bank, the derivative contracts between Isramco and Macquarie Bank were terminated early and the Company received an amount of \$1,737,000 for outstanding hedge positions.

At December 31, 2012, the Company did not have a commodity derivative asset or liability. For the year ended December 31, 2012, the Company recorded a net derivative gain of \$0.2 million (\$2.4 million unrealized loss and a \$2.6 million gain from net cash received on settled contracts).

At December 31, 2011, the Company had a \$2.4 million derivative asset, of which \$1 million was classified as current. For the year ended December 31, 2011, the Company recorded a net derivative loss of \$0.9 million (a \$3.4 million unrealized gain offset by a \$4.3 million loss from net cash paid on settled contracts).

There are no outstanding derivative positions as of December 31, 2013.

Income Tax

Income tax benefit for the year ended December 31, 2013 was \$3,616 million. The tax benefit was primarily due to our pre-tax loss of \$9,940 million which was primarily caused by impairment expense for oil and gas properties in the amount of \$23,161 million for the year ended December 31, 2013.

In 2012 the decrease in income tax expenses was primarily driven by sale of investment in MediaMind shares in 2011 resulted in a net gain of \$15,910,000 comparing to sale of investment in shares of JOEL in 2012 which resulted in net gain of \$3,650,000.

The effective tax rates for the years ended December 31, 2013, 2012 and 2011 were 36%, 31% and 35%, respectively.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. Consolidated Financial Statements and Supplemental Data—Note 1, “Summary of Significant Accounting Policies.”

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk and Derivative Instruments

We are exposed to various risks, including energy commodity price risk. If oil and natural gas prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have adopted a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The type of derivative instrument that we typically utilize is swaps. The total volumes which we hedge through the use of our derivative instruments vary from period to period.

We may be exposed to market risk on our open derivative contracts of non-performance by our counterparties. However, we do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings.

We account for our derivative activities under the provisions of ASC 815, Derivatives and Hedging, (ASC 815). ASC 815 establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. Please refer to Item 8. Consolidated Financial Statements and Supplemental Data—Note 4, "Derivatives and Hedging Activities" for additional information. As of December 31, 2013 we did not have open derivative positions.

Interest-Rate Risk

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk results primarily from fluctuations in short-term rates, which are LIBOR based. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Periodically, we look to utilize interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. As of December 31, 2013 we did not have open interest rate swap positions. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

As of December 31, 2013, we had \$94,657,000 outstanding debt we received from related parties, which is our only variable rate debt. The impact of a hypothetical 1% increase or decrease in interest rates on this amount of debt would have resulted in a corresponding increase or decrease, respectively, in interest expense of approximately \$946,570 and a corresponding increase or decrease, respectively, in net income of approximately \$615,271 during the year ended December 31, 2013. This potential increase or decrease is based on the simplified assumption that the level of variable rate debt remains constant with an immediate across-the-board interest rate increase or decrease as of January 1, 2013.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, Financial Instruments, (ASC 825) are determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. Consolidated Financial Statements and Supplemental Data—Note 6, "Fair Value of Financial Instruments" for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

The information called for by this Item 8 is included following the "Index to Financial Statements" contained in this Annual Report on Form 10-K.

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

None

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ITEM 9A. CONTROLS AND PROCEDURES

DISCLOSURE CONTROLS AND PROCEDURES.

We have established disclosure controls and procedures to ensure that material information relating to Isramco, including its consolidated subsidiaries, is made known to the officers who certify Isramco's financial reports and to other members of senior management and the Board of Directors.

Based on their evaluation, Isramco's principal executive and principal financial officers have concluded that Isramco's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective as of December 31, 2013 to ensure that the information required to be disclosed by Isramco in the reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Isramco's management is responsible for establishing and maintaining adequate internal control over financial reporting for Isramco, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Isramco's management, including our principal executive and principal financial officers, Isramco conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued in 1992 by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO 1992 Framework"). Based on this evaluation under the COSO 1992 Framework, which was completed on March 17, 2014, management concluded that its internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of Isramco's internal control over financial reporting as of December 31, 2013 has been audited by MaloneBailey, LLP, an independent registered public accounting firm who audited Isramco's consolidated financial statements as of and for the year ended December 31, 2013, as stated in their report, which is included under "Item 8. Financial Statements and Supplemental Data" in this report.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in Isramco's internal control over financial reporting during the fourth quarter of 2013 that has materially affected, or is reasonably likely to materially affect, Isramco's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

The information called for by items 10, 11, 12 13 and 14 will be contained in the Company's definitive proxy statement and such information is incorporated herein by reference.

GLOSSARY

"Limited Partnership" means Isramco-Negev 2 Limited Partnership, a Limited Partnership founded pursuant to a Limited Partnership Agreement made on the 2nd and 3rd days of March, 1989 (as amended on September 7, 1989, July 28, 1991, March 5, 1992 and June 11, 1992) between the Trustee on part as Limited Partner and Isramco Oil and Gas Ltd., as General Partner on the other part.

"Overriding Royalty" means a percentage interest over and above the base royalty and is free of all costs of exploration and production, which costs are borne by the Grantor of the Overriding Royalty Interest and which is related to a particular Petroleum License.

"Payout" means the defined point at which one party has recovered its prior costs.

"Petroleum" means any petroleum fluid, whether liquid or gaseous, and includes oil, natural gas, natural gasoline, condensates and related fluid hydrocarbons, and also asphalt and other solid petroleum hydrocarbons when dissolved in and producible with fluid petroleum.

"Israel Petroleum Law"

The Company's business in Israel is subject to regulation by the State of Israel pursuant to the Petroleum Law, 1952. The administration and implementation of the Petroleum Law is vested in the Minister of National Infrastructure (the "Minister") and an Advisory Council.

The following includes brief statements of certain provisions of the Petroleum Law in effect at the date of this Prospectus. Reference is made to the copy of the Petroleum Law filed as an exhibit to the Registration Statement referred to under "Additional Information" and the description which follows is qualified in its entirety by such reference.

The holder of a preliminary permit is entitled to carry out petroleum exploration, but not test drilling or petroleum production, within the permit areas. The Commissioner determines the term of a preliminary permit and it may not exceed eighteen (18) months. The Minister may grant the holder a priority right to receive licenses in the permit areas and for the duration of such priority right no other Party will be granted a license or lease in such areas.

Drilling for petroleum is permitted pursuant to a license issued by the Commissioner. The term of a license is for three (3) years, subject to extension under certain circumstances for an additional period up to four (4) years. A license holder is required to commence test drilling within two (2) years from the grant of a license (or earlier if required by the terms of the license) and not to interrupt operations between test drillings for more than four (4) months. If any well drilled by the Company is determined to be a Commercial discovery prior to expiration of the license, the Company will be entitled to receive a Petroleum Lease granting it the exclusive right to explore for and produce petroleum in the lease area. The term of a lease is for thirty (30) years, subject to renewal for an additional term of twenty (20) years.

The Company, as a lessee, will be required to pay the State of Israel the royalty prescribed by the Petroleum Law which is presently, and at all times since 1952 has been, 12.5% of the petroleum produced from the leased area and

saved, excluding the quantity of petroleum used in operating the leased area.

The Minister may require a lessee to supply at the market price such quantity of petroleum as, in the Minister's opinion, is required for domestic consumption, subject to certain limitations.

As a lessee, the Company will also be required to commence drilling of a development well within six (6) months from the date on which the lease is granted and, thereafter, with due diligence to define the petroleum field, develop the leased area, produce petroleum therefrom and seek markets for and market such petroleum.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Exhibits

- 3.1 Certificate of Incorporation of Registrant with all amendments filed as an Exhibit to the S-1 Registration Statement, File No. 2-83574.
- 3.2 Amendment to Certificate of Incorporation filed March 17, 1993, filed as an Exhibit with the S-1 Registration Statement, File No. 33-57482.
- 3.3 By-laws of Registrant filed as Exhibit 3(ii) to the 8-k filed January 18, 2012 and incorporated herein by reference.
- 4.2 First Amended and Restated Promissory Note dated as of February 27, 2007, issued to NAPHTHA ISRAEL PETROLEUM CORP., LTD. in the principal amount of \$11,500,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.
- 4.3 First Amended and Restated Promissory Note dated as of February 27, 2007, issued to and I.O.C. ISRAEL OIL COMPANY, LTD. in the principal amount of \$12,000,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.
- 4.4 Promissory Note dated as of February 27, 2007, issued to and J.O.E.L JERUSALEM OIL EXPLORATION, LTD. in the principal amount of \$7,000,000, filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.
- 4.5 Promissory Note dated as of May 25, 2009, issued to and J.O.E.L JERUSALEM OIL EXPLORATION, LTD. in the principal amount of \$48,900,000 filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.
- 10.1 Purchase and Sale Agreement, dated as of February 16, 2007, among Five States Energy Company, L.L.C. and each of the other parties listed as a party "Seller" on the signature pages thereof and ISRAMCO, Inc., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.
- 10.2 LOAN AGREEMENT, dated as of February 27, 2007, between ISRAMCO, INC., and NAPHTHA ISRAEL PETROLEUM CORP., LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.
- 10.3 LOAN AGREEMENT, dated as of February 27, 2007, between ISRAMCO, INC., and NAPHTHA ISRAEL PETROLEUM CORP., LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.
- 10.4 LOAN AGREEMENT, dated as of February 27, 2007, Between ISRAMCO, INC., and I.O.C. ISRAEL OIL COMPANY, LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and incorporated herein by reference.
- 10.5 LOAN AGREEMENT, dated as of February 26, 2007, between ISRAMCO, INC., and J.O.E.L JERUSALEM OIL EXPLORATION, LTD., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2007 and

incorporated herein by reference.

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- 10.6 Employment Agreement dated as of September 1, 2007 between Isramco Inc. and Edy Francis, filed as an Exhibit to the 10-Q for the quarter ended September 30, 2007 and incorporated herein by reference.+
- 10.7 Agreement dated as of December 31, 2007 between Isramco Inc. and I.O.C. Israel Oil Company Ltd and addendum dated January 1, 2008, filed as an Exhibit to the 10-Q for the quarter ended March 31, 2008 and incorporated herein by reference.
- 10.8 Amended and restated credit agreement dated on April 28, 2008 between Isramco Resources, LLC and The Bank of Nova Scotia and Capital One, N.A., filed as an Exhibit to the 10-Q for the quarter ended March 31, 2008 and incorporated herein by reference.
- 10.9 Amended and Restated Loan Agreement dated as of May 25, 2008 between Isramco Inc. and J.O.E.L. Jerusalem Oil Explorations Ltd. filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.
- 10.10 Amended and Restated Agreement dated as of November 17, 2008 between Isramco Inc. and Goodrich Global Ltd. filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.
- 10.11 First Amendment to Loan Agreement dated as of February 1, 2009, between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd.(\$18.5 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.
- 10.12 First Amendment to Loan Agreement dated as of February 1, 2009, between Isramco, Inc, and Naphtha Israel Petroleum Corp., Ltd.(\$11.5 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.
- 10.13 Loan Agreement dated as of July 14, 2009 between Isramco, Inc. and I.O.C. – Israel Oil Company, Ltd.(\$6.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.
- 10.14 First Amendment to Loan Agreement dated as of February 1, 2009 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd.(\$12.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2009 and incorporated herein by reference.
- 10.15 Loan Agreement dated as of March 3, 2011 between Isramco, Inc. and I.O.C. – Israel Oil Company, Ltd.(\$11.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2010 and incorporated herein by reference.
- 10.16 First Amendment to Loan Agreement dated as of October 1, 2011 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd. (\$11.0 million) filed as an Exhibit to the 10-K for the year ended December 31, 2011 and incorporated herein by reference.
- 10.17 2011 Stock Incentive Plan filed as an Exhibit to the 10-K for the year ended December 31, 2011 and incorporated herein by reference.
- 10.18 Loan Agreement dated as of February 13, 2013 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd. (1.5 million) filed as an Exhibit to 10-K for the year ended December 2012 and incorporated herein by reference.

- 10.19 Amendment to Loan Agreement dated as of March 1, 2013 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd. filed as an Exhibit to 10-K for the year ended December 2012 and incorporated herein by reference.
- 10.20 Amendment to Loan Agreement dated as of March 1, 2013 between Isramco, Inc. and NAPHTHA ISRAEL PETROLEUM CORP., LTD filed as an Exhibit to 10-K for the year ended December 2012 and incorporated herein by reference.
- 10.21 Amendment to Amended and Restated Loan Agreement and Note between Isramco Inc and J.O.E.L. Jerusalem Oil Exploration, Ltd dated June 30, 2013 filed as an Exhibit to 10-Q for the quarter ended June 2013 and incorporated herein by reference.
- 10.22 Promissory Note dated June 30, 2013, issued to and J.O.E.L JERUSALEM OIL EXPLORATION, LTD. in the principal amount of \$43,700,921 filed as an Exhibit to 10-Q for the quarter ended June 2013 and incorporated herein by reference.
- 10.23 Loan Agreement dated as of March 29, 2012 between Isramco, Inc. and I.O.C. Israel Oil Company, Ltd. (\$3.5 million) filed as an Exhibit to 10K-A for the year ended December 2012 and incorporated herein by reference.
- 10.24 Loan Agreement dated as of April 29, 2012 between Isramco Inc. and I.O.C. Israel Oil Company, Ltd. (\$10.0 million) filed as an Exhibit to 10-Q for the quarter ended June 30, 2012 and incorporated herein by reference.
- 14.1 Code of Ethics, filed as an Exhibit to Form 10-K for the year ended December 31, 2003.
- 23.1* Consent of Cawley, Gillespie & Associates, Inc.
- 23.2* Consent of Netherland, Sewell & Associates, Inc.

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31.1*	<u>Certification of Chief Executive Officer pursuant to Section 302 of Sarbanes-Oxley Act.</u>
31.2*	<u>Certification of Chief Financial Officer pursuant to Section 302 of Sarbanes-Oxley Act</u>
31.3*	<u>Certification of Chief Accounting Officer pursuant to Section 302 of Sarbanes-Oxley Act</u>
32.1*	<u>Certification of Chief Executive and Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 Of the Sarbanes-Oxley act of 2002</u>
32.2*	<u>Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 Of the Sarbanes-Oxley act of 2002</u>
32.3*	<u>Certification of Chief Accounting Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 Of the Sarbanes-Oxley act of 2002</u>
99.1*	<u>Cawley, Gillespie & Associates, Inc. Reserves Report</u>
99.2*	<u>Netherland, Sewell & Associates, Inc. Reserves Report</u>
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Linkbase
101.LAB	XBRL Taxonomy Extension Label Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase

* Filed Herewith.

+ Management Agreement

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SIGNATURES

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

/S/ HAIM TSUFF
HAIM TSUFF,
CHAIRMAN OF THE BOARD,
CHIEF EXECUTIVE OFFICER
(PRINCIPAL EXECUTIVE OFFICER)

Date: March 17, 2014

/S/ EDY FRANCIS
EDY FRANCIS,
CHIEF FINANCIAL OFFICER
(PRINCIPAL FINANCIAL OFFICER)

Date: March 17, 2014

/S/ ZEEV KOLTOVSKOY
ZEEV KOLTOVSKOY,
CHIEF ACCOUNTING OFFICER
(PRINCIPAL ACCOUNTING OFFICER)

Date: March 17, 2014

Pursuant to the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Haim Tsuff Haim Tsuff	Chairman of the Board & Chief Executive Officer	March 17, 2014
/s/ Josef From Josef From	Director	March 17, 2014
/s/ Max Pridgeon Max Pridgeon	Director	March 17, 2014
/s/ Frans Sluiter Frans Sluiter	Director	March 17, 2014
/s/ Itai Ram	Director	March 17, 2014

Itai Ram

/s/ Asaf Yarkoni
Asaf Yarkoni

Director

March 17, 2014

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<u>Report of Independent Registered Public Accounting Firm</u>	F-2
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<u>Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011</u>	F-4
<u>Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011</u>	F-5
<u>Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2013, 2012 and 2011</u>	F-6
<u>Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011</u>	F-7
<u>Notes to Consolidated Financial Statements</u>	F-8

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MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Isramco, Inc. (the “Company”), including the Company’s Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company’s internal control system was designed to provide reasonable assurance to the Company’s Management and Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on this evaluation, management concluded that the Company’s internal control over financial reporting was effective as of December 31, 2013.

MaloneBailey, LLP, the Company’s independent registered public accounting firm, has issued an attestation report on the effectiveness on our internal control over financial reporting as of December 31, 2013.

/s/ Haim	/s/ Zeev	/s/ Edy
Tsuff	Koltovskoy	Francis
Haim Tsuff	Zeev Koltovskoy	Edy Francis
Chief Executive Officer	Chief Accounting Officer	Chief Financial Officer

Houston, Texas
March 17, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Iramco, Inc.
Houston, Texas

We have audited the accompanying consolidated balance sheets of Iramco, Inc. and its subsidiaries (collectively the “Company”) as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, changes in shareholders’ equity, and cash flows for each of the three years in the period ended December 31, 2013. We also have audited the Company’s internal control over financial reporting as of December 31, 2013, 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 these consolidated financial statements, 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 Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on these consolidated financial statements and an opinion on the Company’s internal control over financial reporting 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 and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Isramco, Inc and its subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ MALONE BAILEY, LLP

www.malone-bailey.com

Houston, Texas

March 17, 2014

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ISRAMCO INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

As of December 31	ASSETS	2013	2012
Current Assets:			
Cash and cash equivalents		\$ 4,149	\$ 615
Accounts receivable, net of allowances for doubtful accounts of \$536 and \$349		14,755	11,856
Restricted and designated cash		1,561	61
Inventories		428	122
Deferred tax assets		6,539	4,160
Prepaid expenses and other		911	572
Total Current Assets		28,343	17,386
Property and Equipment, at cost – successful efforts method:			
Oil and Gas properties		236,399	231,327
Advanced payment for equipment		330	98
Other		36,836	18,987
Total Property and Equipment		273,565	250,412
Accumulated depreciation, depletion, amortization and impairment		(153,147)	(117,799)
Net Property and Equipment		120,418	132,613
Deferred tax assets and other		9,152	3,959
Total assets		\$ 157,913	\$ 153,958
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accrued expenses		\$ 13,906	\$ 13,208
Bank overdraft		791	773
Short term debt		601	-
Due to related party and accrued interest		15,275	21,749
Total current liabilities		30,573	35,730
Due to related party and accrued interest		96,035	81,505
Other Long-term Liabilities:			
Asset retirement obligations		18,814	17,908
Total other long-term liabilities		18,814	17,908
Commitments and contingencies (Note 13)			
Shareholders' equity:			
Common stock \$0.01 par value; authorized 7,500,000 shares; issued 2,746,958 shares; outstanding 2,717,691 shares		27	27
Additional paid-in capital		23,268	23,268
Accumulated deficit		(11,257)	(4,547)
Treasury stock, 29,267 shares at cost		(164)	(164)

Total Iramco, Inc. shareholders' equity	11,874	18,584
Non controlling interest	617	231
Total equity	12,491	18,815
Total liabilities and shareholders' equity	\$ 157,913	\$ 153,958

See notes to the consolidated financial statements.

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ISRAMCO INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except share and per share amounts)

Year Ended December 31	2013	2012	2011
Revenues			
Oil and gas sales	\$ 51,288	\$ 40,402	\$ 44,228
Production services	16,294	9,279	896
Office services	642	564	437
Other	468	185	87
Total revenues	68,692	50,430	45,648
Operating expenses			
Lease operating expense, transportation and taxes	19,974	19,737	20,981
Depreciation, depletion and amortization	12,187	11,350	9,982
Impairments of oil and gas assets	23,161	1,225	4,034
Accretion expense	902	875	853
Production services	10,837	6,427	675
Loss from plug and abandonment	226	314	315
General and administrative	4,734	4,505	4,438
Total operating expenses	72,021	44,433	41,278
Operating income (loss)	(3,329)	5,997	4,370
Other expenses (income)			
Interest expense, net	6,528	6,339	7,760
Realized gain on marketable securities	-	(3,650)	(15,910)
Net loss (gain) on derivative contracts	-	(219)	922
Currency exchange rate differences	-	(15)	237
Capital loss	83	-	-
Total other expenses (income)	6,611	2,455	(6,991)
Income (loss) before income taxes	(9,940)	3,542	11,361
Income tax benefit (expense)	3,616	(1,095)	(3,975)
Net income (loss)	\$ (6,324)	\$ 2,447	\$ 7,386
Net income attributable to non-controlling interests	386	226	5
Net income (loss) attributable to Isramco	\$ (6,710)	\$ 2,221	\$ 7,381
Earnings (loss) per share – basic:	\$ (2.47)	\$ 0.82	\$ 2.72
Earnings (loss) per share – diluted:	\$ (2.47)	\$ 0.82	\$ 2.72
Weighted average number of shares outstanding-basic:	2,717,691	2,717,691	2,717,691
Weighted average number of shares outstanding-diluted:	2,717,691	2,717,691	2,717,691

See notes to the consolidated financial statements.

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ISRAMCO INC.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands, except share and per share amounts)

Year Ended December 31	2013	2012	2011
Net income (loss)	\$ (6,324)	\$ 2,447	7,386
Other comprehensive income			
Available-for-sale securities, net of taxes	-	(2,254)	(7,397)
Change in unrealized gains on hedging instruments, net of taxes	-	-	22
Comprehensive income	\$ (6,324)	\$ 193	11
Comprehensive income attributable to non-controlling interests	386	226	5
Comprehensive income (loss) attributable to Isramco	\$ (6,710)	\$ (33)	6

See notes to the consolidated financial statements.

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ISRAMCO INC.
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2013, 2012 and 2011

	Common stock		Additional Paid-In Capital	Accumulated other comprehensive income (loss)		Retained Earnings (Accumulated Deficit)	Treasury stock	Non-controlling interests	Total Shareholders' Equity
	Number of shares	Amount		income	(loss)				
\$ in thousands, except share amounts									
Balance of January 1, 2011	2,717,691	\$ 27	\$ 23,194	\$ 9,629	\$ (14,149)	\$ (164)	\$ -	\$ -	\$ 18,537
Net income					7,381			5	7,386
Net unrealized loss on available for sale marketable securities, net of taxes of \$3,983				(7,397)					(7,397)
Net gain on derivative contracts, net of taxes \$12				22					22
Total comprehensive loss									(7,375)
Balance of December 31, 2011	2,717,691	\$ 27	\$ 23,194	\$ 2,254	\$ (6,768)	\$ (164)	\$ 5	\$ 5	\$ 18,548
Net income					2,221			226	2,447
Proceeds from short swing profits from parent company			74						74
Net unrealized gain on available for sale marketable securities, net of taxes of \$1,214				(2,254)					(2,254)
Total comprehensive gain									(2,254)

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Balance of December 31, 2012	2,717,691	\$ 27	\$ 23,268	\$ -	\$ (4,547)	\$ (164)	\$ 231	\$ 18,815
Net loss					(6,710)		386	(6,324)
Balance of December 31, 2013	2,717,691	\$ 27	\$ 23,268	\$ -	\$ (11,257)	\$ (164)	\$ 617	\$ 12,491

See notes to consolidated financial statements.

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ISRAMCO INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

Year Ended December 31	2013	2012	2011
Cash Flows From Operating Activities:			
Net income (loss)	\$ (6,324)	\$ 2,447	\$ 7,386
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, amortization	12,187	11,350	9,982
Impairment of oil and gas properties	23,161	1,225	4,034
Bad debt expense	187	-	-
Accretion expense	902	875	853
Realized gain on marketable securities	-	(3,650)	(15,910)
Changes in deferred taxes	(3,616)	1,095	3,975
Net unrealized loss (gain) on derivative contracts	-	2,382	(3,384)
Capital loss	83	-	-
Amortization of debt cost	-	70	252
Changes in components of working capital and other assets and liabilities			
Accounts receivable	(3,086)	(5,397)	(349)
Prepaid expenses and other current assets	(3,359)	(20)	(86)
Due to related party	27	4,253	959
Inventories	(307)	(36)	(86)
Accounts payable and accrued expenses	(2,101)	2,406	(680)
Accrued interest – related party	6,528	-	-
Net cash provided by operating activities	24,282	17,000	6,946
Cash flows from investing activities:			
Addition to property and equipment, net	(20,478)	(16,997)	(9,060)
Proceeds from sale of gas properties and equipment	-	-	32
Proceeds from sale of equipment	47	-	-
Restricted cash and deposit, net	(1,500)	229	598
Proceeds from sale of marketable securities	-	4,737	16,073
Net cash provided by (used in) investing activities	(21,931)	(12,031)	7,643
Cash flows from financing activities:			
Repayments on loans – related parties, net	-	-	(12,537)
Proceeds on loans-related parties , net	1,500	13,500	11,000
Repayment of long-term debt	-	(20,000)	(17,075)
Repayment of short-term debt	(335)	-	-
Borrowings of bank overdraft, net	18	24	488
Net cash provided by (used in) financing activities	1,183	(6,476)	(18,124)
Net increase (decrease) in cash and cash equivalents	3,534	(1,507)	(3,535)
Cash and cash equivalents at beginning of year	615	2,122	5,657
Cash and cash equivalents at end of year	\$ 4,149	\$ 615	\$ 2,122

See notes to the consolidated financial statements.

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ISRAMCO INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Isramco, Inc. and its subsidiaries and affiliated companies (together referred to as “We”, “Our”, “Isramco” or the “Company”) is predominately an independent oil and natural gas company engaged in the exploration, development and production of oil and natural gas properties located onshore in the United States and ownership of various royalty interests in oil and gas concessions located offshore Israel. The Company also operates a well service company that provides well maintenance and workover, well completion and recompletion services. The Company’s consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All intercompany accounts and transactions have been eliminated. The Company has evaluated events or transactions through the date of issuance of this report in conjunction with the preparation of these consolidated financial statements.

Use of Estimates

In preparing financial statements in accordance with accounting principles generally accepted in the United States, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to the value of properties and equipment; proved reserves; intangible assets; asset retirement obligations; litigation reserves; environmental liabilities; liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Measurements

Certain of Isramco’s assets and liabilities are measured at fair value at each reporting date. Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants. This price is commonly referred to as the “exit price.” Fair value measurements are classified according to a hierarchy that prioritizes the inputs underlying the valuation techniques. This hierarchy consists of three broad levels:

- Level 1 – Inputs consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. When available, Isramco measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.
- Level 2 – Inputs consist of quoted prices that are generally observable for the asset or liability. Common examples of Level 2 inputs include quoted prices for similar assets and liabilities in active markets or quoted prices for identical assets and liabilities in markets not considered to be active.
- Level 3 – Inputs are not observable from objective sources and have the lowest priority. The most common Level 3 fair value measurement is an internally developed cash flow model.

Cash and Cash Equivalents.

Isramco records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

Restricted and designated cash.

Restricted cash deposits are held in favor of financial institutions and represent deposits with original maturity of longer than three month.

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectability and establishes or adjusts the allowance as necessary by using both the specific identification method and/or general allowance as a percentage of outstanding accounts receivable balances.

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Oil and Gas Operations.

The Company applies the successful efforts method of accounting for oil and gas properties. Under the successful efforts method, exploration costs such as exploratory geological and geophysical costs, delay rentals and exploration overhead are charged against earnings as incurred. Acquisition costs and costs of drilling exploratory wells are capitalized pending determination of whether proved reserves can be attributed to the area as a result of drilling the well. If management determines that commercial quantities of hydrocarbons have not been discovered, capitalized costs associated with exploratory wells are charged to exploration expense. Acquisition costs of unproved leaseholds are assessed for impairment during the holding period and transferred to proved oil and gas properties to the extent associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated.

Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Amortization rates are updated to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

The Company reviews its property and equipment in accordance with Accounting Standard Codification (ASC) 360, Property, Plant, and Equipment ("ASC 360"). ASC 360 requires the Company to evaluate property and equipment as an event occurs or circumstances change that would more likely than not reduce the fair value of the property and equipment below the carrying amount. If the carrying amount of property and equipment is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the discounted cash flow.

In 2013, 2012 and 2011, we reported an impairment charge of \$23,161,000, \$1,225,000 and \$4,034,000, respectively, relating to our oil and gas properties. Impairments of oil and gas assets of \$23,161,000 in 2013 were a result of lower estimated future crude oil, natural gas and NGLs prices which are basis for an impairment calculation and a decrease in production volumes in 2013. In 2012 the impairments of oil and gas assets of \$1,225,000 were primarily a result of lower natural gas prices in general and the low volume of gas produced in a few of our fields. Impairments of oil and gas assets of \$4,034,000 in 2011 were primarily a result of lower natural gas prices in general and the low volume of gas produced in a few of our fields.

Property, Plant and Equipment Other than Oil and Natural Gas Properties

Property and equipment are carried at cost less accumulated depreciation. Depreciation is provided for our assets over the estimated depreciable lives of the assets using the straight-line method. Depreciation expense for the years ended December 31, 2013, 2012 and 2011 was \$1,767,000, \$926,000 and \$246,000 respectively. We depreciate our operational assets over their depreciable lives to their salvage value, which is a fair value higher than the assets' value as scrap. Salvage value approximates 15% of an operational asset's acquisition cost. When an operational asset is stacked or taken out of service, we review its physical condition, depreciable life and ultimate salvage value to determine if the asset is no longer operable and whether the remaining depreciable life and salvage value should be adjusted. When we scrap an asset, we accelerate the depreciation of the asset down to its salvage value. When we dispose of an asset, a gain or loss is recognized. We did not identify any triggering events or record any asset

impairments during 2013, 2012 and 2011.

As of December 31, 2013, the estimated useful lives of our asset classes are as follows:

Description	Years
Well service rigs and components	15
Oilfield trucks, vehicles and related equipment	7 - 10
Well service auxiliary equipment	7 - 15
Furniture and equipment	3 - 7

A long-lived asset or asset group should be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. For purposes of testing for impairment, we group our long-lived assets along our lines of business based on the services provided, which is the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. We would record an impairment charge, reducing the net carrying value to an estimated fair value, if the asset group's estimated future cash flows were less than its net carrying value. Events or changes in circumstance that cause us to evaluate our fixed assets for recoverability and possible impairment may include changes in market conditions, such as adverse movements in the prices of oil and natural gas, or changes of an asset group, such as its expected future life, intended use or physical condition, which could reduce the fair value of certain of our property and equipment. The development of future cash flows and the determination of fair value for an asset group involves significant judgment and estimates.

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Marketable Securities

The Company may invest a portion of its cash in money market mutual funds which are highly liquid marketable securities. The Company accounts for marketable securities in accordance with Financial Accounting Standards Board's (FASB) ASC 320, Investments—Debt and Equity Securities, (ASC 320) and classifies marketable securities as trading, available-for-sale, or held-to-maturity. The appropriate classification of its marketable securities is determined at the time of purchase and reevaluated at each balance sheet date.

Trading and available-for-sale securities are recorded at fair market value. Isramco held no held-to-maturity securities. Unrealized holding gains and losses on trading securities are included in earnings. Unrealized holding gains or losses, net of the related tax effects, on available-for-sale securities were excluded from earnings and were reported net of applicable taxes as accumulated other comprehensive income, a separate component of shareholders' equity, until realized. As of December 31, 2013 the company did not have marketable securities balance.

Asset Retirement Obligation

ASC 410, Asset Retirement and Environmental Obligations (ASC 410) requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company's legal obligations related to future plugging and abandonment of its oil and natural gas wells and gas gathering systems. The Company estimates the expected cash flow associated with the obligation and discounts the amounts using a credit-adjusted, risk-free interest rate. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells as these obligations are incurred. See "Note 14 Asset Retirement Obligations."

Concentrations of Credit Risk

The Company through its wholly-owned subsidiary operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the Company's joint interest partners to reimburse the Company could also be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. The Company does not believe the loss of any one of its purchasers would materially affect the Company's ability to sell the oil and natural gas it produces. The Company believes other purchasers are available in the Company's areas of operations.

In 2013, one individual purchaser of the Company's production accounted for 41% of the Company's total sales and an additional two individual purchasers of the Company's production accounted for approximately 19% of its total sales (one purchaser approximately 12% and another approximately 7%), collectively representing 59% of the Company's total sales. In 2012, one individual purchaser of the Company's production accounted for 41% of the Company's total sales and an additional two individual purchasers of the Company's production accounted for approximately 21% of

its total sales (one purchaser approximately 14% and another approximately 7%), collectively representing 62% of the Company's total sales. In 2011, one individual purchaser of the Company's production accounted for 30% of the Company's total sales and an additional three individual purchasers of the Company's production accounted for approximately 26% of its total sales (two purchasers approximately 9% each and another approximately 8%), collectively representing 56% of the Company's total sales.

We own an overriding royalty interest of 1.5375% in the Tamar Field, which will increase to 2.7375% after payout (collectively the "Tamar Royalty"). On March 31, 2013 the Tamar Field commenced its initial production of the natural gas. During the year ended December 31, 2013, one individual customer of Tamar sales revenues accounted for 62% and an additional two individual customers accounted for 14% and 11% of Tamar total sales. No other customer accounted for more than 10% of subsidiary's revenue in 2013.

Our well service subsidiary customers include major oil and natural gas production companies and independent oil and natural gas production companies. We perform credit evaluations of our customers and usually do not require collateral. We maintain reserves for potential credit losses when necessary.

During the year ended December 31, 2013, one individual customer accounted for 10% of the well service subsidiary consolidated revenues. No other customer accounted for more than 10% of subsidiary's revenue in 2013.

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During the year ended December 31, 2012, one individual customer accounted for 21% of the well service subsidiary consolidated revenues and an additional two individual customers accounted for 19% and 15% of subsidiary's total sales. No other customer accounted for more than 10% of subsidiary's revenue in 2012.

Revenue Recognition

Revenues from the sale of oil and natural gas are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. The Company follows the sales method of accounting for recording oil and gas revenues. Under this method, the company records revenue based on the actual sale of volumes to purchasers. In the past the company used entitlement method of accounting. Under this method any revenues received in excess of the Company's interest in production are treated as a liability. If revenues received are less than Company's interest in production, the deficiency is recorded as an asset. In terms of volumes and values, the Company's imbalance position was not significant at December 31, 2013 and 2012. There were no accounting transactions necessary for imbalances during this time-period.

Revenues from our well service activities are recognized when all of the following criteria have been met: (i) evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the price to the customer is fixed and determinable and (iv) collectability is reasonably assured.

- Evidence of an arrangement exists when a final understanding between us and our customer has occurred, and can be evidenced by a completed customer purchase order, field ticket, supplier contract, or master service agreement.
- Delivery has occurred or services have been rendered when we have completed requirements pursuant to the terms of the arrangement as evidenced by a field ticket.
- The price to the customer is fixed and determinable when the amount that is required to be paid is agreed upon. Evidence of the price being fixed and determinable is evidenced by contractual terms, our price book, a completed customer purchase order, or a field ticket.
- Collectability is reasonably assured when we screen our customers and provide goods and services to customers according to determined credit terms that have been granted based on credit evaluation and assessment.

We present our revenues net of any sales taxes collected by us from our customers that are required to be remitted to local or state governmental taxing authorities.

Price Risk Management Activities

The Company follows ASC 815, Derivatives and Hedging. From time to time, the Company may hedge a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company consist of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in "Net gain (loss) on derivative contracts" on the Company's consolidated statements of operations.

In 2012 and 2011, we recorded gain (loss) of \$0.2 million, (\$0.9) million respectively, related to our derivative instruments. Fair values are derived principally from market quoted and other independent third-party quotes.

On August 15, 2012, pursuant to an agreement with Macquarie Bank, the derivative contracts between Isramco and Macquarie Bank were terminated early and the Company received an amount of \$1,737,000 for outstanding hedge positions.

As of the date of this report there are no open hedge positions.

During the second quarter of 2008, we made the decision to mitigate a portion of our interest rate risk with interest rate swaps. These swap instruments reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. These interest rate swaps convert a portion of our variable rate interest of our Scotia debt (as defined in Note 5, "Long-term Debt and Interest Expense") to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. We have elected to designate these positions for hedge accounting and therefore the unrealized gains and losses are recorded in accumulated other comprehensive loss. The Company measures hedge effectiveness by assessing the changes in the fair value or expected future cash flows of the hedged item.

As of the date of this report there are no open interest rate swap positions.

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Income Taxes

We account for deferred income taxes using the asset and liability method and provide deferred taxes for all significant temporary differences. Management determines our current tax liability as well as taxes incurred as a result of current operations, but which are deferred until future periods. Current taxes payable represent our liability related to our income tax returns for the current year, while net deferred tax expense or benefit represents the change in the balance of deferred tax assets and liabilities reported on our consolidated balance sheets. Management estimates the changes in both deferred tax assets and liabilities using the basis of assets and liabilities for financial reporting purposes and for enacted rates that management estimates will be in effect when the differences reverse. Further, management makes certain assumptions about the timing of temporary tax differences for the differing treatments of certain items for tax and accounting purposes or whether such differences are permanent. The final determination of our tax liability involves the interpretation of local tax laws, tax treaties, and related authorities in each jurisdiction as well as the significant use of estimates and assumptions regarding the scope of future operations and results achieved and the timing and nature of income earned and expenditures incurred.

We establish valuation allowances to reduce deferred tax assets if we determine that it is more likely than not (e.g., a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized in future periods. To assess the likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which this taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted results, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry. Additionally, we record uncertain tax positions at their net recognizable amount, based on the amount that management deems is more likely than not to be sustained upon ultimate settlement with the tax authorities in the domestic and international tax jurisdictions in which we operate.

See “Note 7 Income Taxes” for further discussion of accounting for income taxes, changes in our valuation allowance, components of our tax rate reconciliation and realization of loss carryforwards.

Legal Contingencies

When estimating our liabilities related to litigation, we take into account all available facts and circumstances in order to determine whether a loss is probable and reasonably estimable.

Various suits and claims arising in the ordinary course of business are pending against us. We conduct business throughout the continental United States and may be subject to jury verdicts or arbitrations that result in outcomes in favor of the plaintiffs. We continually assess our contingent liabilities, including potential litigation liabilities, as well as the adequacy of our accruals and our need for the disclosure of these items. We establish a provision for a contingent liability when it is probable that a liability has been incurred and the amount is reasonably estimable.

Earnings per Share

The Company’s basic earnings per share (EPS) amounts have been computed based on the average number of shares of common stock outstanding for the period and include the effect of any participating securities as appropriate. Diluted EPS includes the effect of the Company’s outstanding stock options, restricted stock awards, restricted stock units and performance-based stock awards if the inclusion of these items is dilutive.

For the year ended December 31, 2013, Isramco's stock options were anti-dilutive.

Noncontrolling Interests

Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiary and are presented as a component of equity.

Environmental

The Company accrues for losses associated with environmental remediation obligations when such losses are probable and can be reasonably estimated. Accruals for estimated losses from environmental remediation obligations are recognized no later than the time of the completion of the remediation feasibility study or remediation plan. These accruals are adjusted as additional information becomes available or as circumstances change. Costs of future expenditures for environmental remediation obligations are not discounted to their present value.

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Recently Issued Accounting Pronouncements

In February 2013, the FASB issued ASU 2013-02 "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). ASU 2013-02 amends ASU 2011-05 and requires that entities disclose additional information about amounts reclassified out of Accumulated Other Comprehensive Income (AOCI) by component. Significant amounts reclassified out of AOCI are required to be presented either on the face of the Consolidated Statements of Income and Comprehensive Income or in the notes to the financial statements. The requirements of ASU 2013-02 are effective for fiscal years and interim periods in those years beginning after December 15, 2013. Isramco does not expect the adoption of ASU 2013-02 to have a material impact on Isramco's financial statements.

2. Transactions with Affiliates and Related Parties

On November 17, 2008, the Company and Goodrich Global, Ltd. ("Goodrich") entered into an Amended and Restated Agreement, as subsequently amended on November 24, 2008 ("Restated Agreement"). The Restated Agreement replaced the consulting agreement originally entered into in May 1996. Under the the Restated Agreement, the Company pays to Goodrich, which is owned and controlled by Haim Tsuff, the Chairman of the Board of Directors and Chief Executive Officer of Isramco, \$360,000 per annum in installments of \$30,000 per month, in addition to reimbursing Goodrich for all reasonable expenses incurred in connection with services rendered on behalf of the Company. Goodrich was also entitled to receive, with respect to each completed fiscal year beginning with the fiscal year ended on December 31, 2008, an amount in cash equal to five percent (5%) of the Company's pre-tax recorded profit calculated without reference to gain or loss in derivative transactions (the "Supplemental Payment"). The Restated Agreement had an initial term through May 31, 2011; provided that the term of the Restated Agreement will be deemed to have been automatically extended for an additional three year period unless the Company furnished Goodrich, by March 3, 2011, with written notice of its election to not extend the term of such agreement. The Company did not furnish notice of termination, and the Restated Agreement was accordingly extended. The Restated Agreement contains certain customary confidentiality and non-compete provisions. If the Restated Agreement is terminated by the Company other than for cause, then Goodrich is entitled to receive the equivalent of payments due through the then remaining term of the agreement. For the year ended December 31, 2013, 2012 and 2011 we paid Goodrich the total amount of \$360,000, \$360,000 and \$360,000, respectively. The conditions precedent for Supplemental Payments were not met and no Supplemental Payments have been made. In addition, in connection with the settlement of the Derivative Litigation in 2012, the parties to the Restated Agreement amend the Restated Agreement to eliminate the provisions providing for Supplemental Payment.

3. Marketable Securities

During February 2012 the Company sold all of its investment in shares of Jerusalem Oil Exploration Ltd. ("JOEL") to Equital Ltd. Both JOEL and Equital Ltd. are related parties of Isramco Inc. JOEL is also a subsidiary of Equital Ltd. The Company recorded a net gain of \$3,650,000.

In August 2011 the Company sold all of its investment in a company called MediaMind Ltd. The realized gain from this transaction amounted to \$15,910,000.

Sales of marketable securities resulted in realized gains of \$0, \$3,650,000 and \$15,910,000 for the years ended December 31, 2013, 2012 and 2011, respectively.

As of the date of this report there are no investments in marketable securities.

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4. Derivative and Hedging Activities

The Company may enter into derivative commodity contracts to economically hedge its exposure to price fluctuations on a portion of its anticipated oil and natural gas production. It is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers.

As of December 31, 2013, the Company did not have any commodity derivative assets. For the year ended December 31, 2013, there were no commodity derivative activities.

As of December 31, 2011 we had swap contracts for volume of 48,567 barrels of crude oil during 36 months, commencing January 2013, and swap contracts for volume of 270,613 MMBTU of natural gas during 3 months commencing January 2013. Derivative commodity contracts settle based on NYMEX West Texas Intermediate and Henry Hub prices, which may differ from the actual price received by the Company.

During 2013, 2012 and 2011 the Company did not elect to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the net change in the mark-to-market valuation of these contracts, as well as all payments and receipts on settled contracts, in current earnings as a component of other income and expenses on the consolidated statements of operations.

On March 9, 2011, pursuant to an agreement with Wells Fargo, the derivative contracts between Isramco and Wells Fargo were terminated and the Company signed new swap contracts with Macquarie Bank, N.A. for an aggregate volume of 336,780 barrels of crude oil during the forty-six (46) month period commencing March 2011. The required payment to Wells Fargo for the termination of the aforementioned contracts was approximately \$7 million. Subsequently, on August 15, 2012, pursuant to an agreement with Macquarie Bank, the derivative contracts between Isramco and Macquarie Bank were terminated early and the Company received an amount of \$1,737,000 for its outstanding hedge positions.

At December 31, 2012, the Company did not have a commodity derivative asset. For the year ended December 31, 2012, the Company recorded a net derivative gain of \$0.2 million (\$2.4 million unrealized loss and a \$2.6 million gain from net cash received on settled contracts).

At December 31, 2011, the Company had a \$2.4 million derivative asset, of which \$1 million was classified as current. For the year ended December 31, 2011, the Company recorded a net derivative loss of \$0.9 million (a \$3.4 million unrealized gain offset by a \$4.3 million loss from net cash paid on settled contracts).

During the second quarter of 2008, we made the decision to mitigate a portion of our interest rate risk with interest rate swaps. These swap instruments reduce our exposure to market rate fluctuations by converting variable interest rates to fixed interest rates.

Under these swaps, the Company makes payments to, or receives payments from, the counterparties based upon the differential between a specified fixed price and a price related to the one-month London Interbank Offered Rate ("LIBOR"). These interest rate swaps convert a portion of the variable rate interest of our Senior Credit Facility (as defined in Note 5, "Long-term Debt and Interest Expenses") to a fixed rate obligation, thereby reducing the exposure to market rate fluctuations. We have elected to designate these positions for hedge accounting and therefore the unrealized gains and losses are recorded in accumulated other comprehensive loss. The Company measures hedge effectiveness by assessing the changes in the fair value or expected future cash flows of the hedged item.

As of December 31, 2013 the Company did not have open interest rate swap positions.

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5. Long-Term Debt and Interest Expense

Long-Term Debt as December 31 consisted of the following (in thousands):

	2013	2012
Libor + 6% Related party Debt	12,000	12,000
Libor + 5.5% Related party Debt	3,500	3,500
Libor + 5.5% Related party Debt	10,000	10,000
Libor + 6% Related party Debt	11,500	11,500
Libor + 6% Related party Debt	6,000	6,000
Libor + 6% Related party Debt (1)	43,701	41,861
Libor + 5.5% Related party Debt	6,456	6,456
Libor + 6% Related party Debt	1,500	-
Accrued interest	16,299	11,609
	110,956	102,926
Less: Current Portion of Long-Term Debt and Accrued Interest	(14,921)	(21,421)
Total	96,035	81,505

(1) An amendment of loan agreement between Company and related party extended the term of this loan and covered an amount equal to the unpaid principal balance and accrued interest as of the effective date thereof.

Senior Revolving Credit Facilities

The Company entered into a Senior Secured Revolving Credit Agreement, dated as of March 27, 2008. The Bank of Nova Scotia was the administrative agent for the Lenders and Capital One, N.A. was the syndication agent for the Lenders. The Scotia Senior Credit Agreement originally provided for a \$150 million facility due in 2013. During the fourth quarter of 2011, the Lenders reduced the borrowing base to \$0. On April 27, 2012, The Company entered into the Fourth Amendment to the Credit Agreement with Lenders, formalizing the election to pay the \$20,000,000 borrowing base deficiency in six monthly installments of \$3,333,333.33 and extended the termination date to June 29, 2012. As of June 29, 2012 the Company has fully paid all amounts owed and terminated this Senior Credit Facility.

The Company entered into a Senior Secured Revolving Credit Agreement, dated as of March 2, 2007 with Wells Fargo Bank, N.A. as administrative agent for the Lenders. The Wells Fargo Senior Credit Agreement originally provided for a \$150 million facility due in March 2011. On or about March 3, 2011, the Company paid the outstanding principal balance of the Wells Fargo Senior Credit Facility

The Wells Fargo Senior Credit Facility was transferred to and assumed by Macquarie Bank, N.A. The Macquarie Bank N.A. credit facility has been terminated and there are no outstanding balances.

The Company does not presently have a credit facility but is in negotiations to obtain a commercial loan from financial institution. The Company is uncertain as to whether it will be successful in obtaining this new commercial loan.

Related Party Debt

I.O.C. Israel Oil Company, Ltd. ("IOC")

On February 27, 2007, Isramco obtained a loan in the principal amount of \$12,000,000 from IOC, repayable at the end of five years. Interest accrues at a per annum rate of LIBOR plus 6%. Principal is due and payable in four equal annual installments, commencing on the second anniversary of the loan. Accrued interest is payable in equal annual installments. At any time Isramco can make prepayments without premium or penalty. The loan is not secured.

In July 2009, the Company entered into a loan transaction with IOC, a related party, pursuant to which the Company borrowed \$6 million (the "IOC Loan"). Amounts outstanding under the IOC Loan bear interest at LIBOR plus 6.0%. The IOC Loan matures in five years, with accrued interest payable annually on each anniversary date of the loan. The IOC Loan may be prepaid at any time without penalty.

Effective February 1, 2009, the loan from IOC was amended and restated to extend the payment deadlines arising on and after February 2009, by two years.

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On March 3, 2011, the Company entered into a Loan Agreement with IOC pursuant to which it borrowed the sum of \$11,000,000. The loan bears interest at a rate of 10% per annum and is payable in quarterly payments of interest only until March 3, 2013, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty. The loan is unsecured. During September 2011, Isramco paid \$4,544,000 of principal pursuant to this Loan agreement with IOC leaving outstanding principle of \$6,456,000.

Subsequently, in October 2011 the agreement with IOC, pertaining to the above mentioned loan in the outstanding principal amount of \$6,456,000 was renegotiated. The payoff of principal amount was extended by 6 month to September 9, 2013. Interest accrued per annum was determined on LIBOR+5.5% from initial 10%.

On March 29, 2012, the Company entered into a Loan Agreement with IOC pursuant to which it borrowed \$3,500,000. The loan bears interest at a rate of Libor + 5.5% per annum and matures on March 29, 2013, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty or premium. The loan is unsecured.

On April 29, 2012, the Company entered into another Loan Agreement with IOC, pursuant to which it borrowed \$10,000,000. The loan bears interest of Libor+5.5% per annum and matures on April 30, 2013, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty or premium. The loan was funded by IOC in three monthly installments starting April 2013. The loan is unsecured. The purpose of the loan was to provide funds to Isramco for the payment of amounts that were due to the Lenders under the Senior Credit Facility that was paid in full June 29, 2013.

On February 13, 2013, the Company entered into another Loan Agreement with IOC, pursuant to which it borrowed \$1,500,000. The loan bears interest of Libor+6% per annum and matures on February 13, 2018, when all accrued interest and principal is due and payable. The loan may be prepaid at any time without penalty or premium. The loan is unsecured. The purpose of the loan was to provide funds to back up a Letter of Credit.

On March 1, 2013, all of the above-mentioned Loan agreements and notes with IOC except for the \$1,500,000 loan agreement entered on February 13, 2013, were amended. The terms of all these loans and notes between the Company and IOC were amended extending the maturity to December 31, 2018. In addition the payment schedule was changed on the all of the loans and notes to require accrued interest only payments December 31, 2014, December 31, 2015, December 31, 2016, December 31, 2017 and final interest payment December 31, 2018 with outstanding principal paid in four equal installments with the first payment December 31, 2015 and a similar payment made December 31 in each of the following three years until the final payment on December 31, 2018. The other terms of the loan agreements and notes remained unchanged. In accordance with the amendment, as of December 31, 2013 the loans are classified as long-term on our consolidated balance sheets.

The Company evaluated the application of ASC 470-50 "Debt Modification and Extinguishment" and ASC 470-60 "Troubled Debt Restructuring" and concluded that the revised terms constituted a debt modification, rather than a debt extinguishment or a troubled debt restructuring.

Mr. Haim Tsuff, Isramco's Chief Executive Officer and Chairman and is a controlling shareholder of IOC.

Naphtha Israel Petroleum Corp. Ltd., ("Naphtha")

In connection with the Company's purchase of certain oil and gas interests mainly in New Mexico and Texas in February 2007, the Company obtained loan from Naphtha, a related party, with terms and conditions as below:

On February 27, 2007, Isramco obtained a loan, in the principal amount of \$11,500,000 from Naphtha, repayable at the end of seven years. Interest accrues at a per annum rate of LIBOR plus 6%. Principal is due and payable in four equal installments, commencing on the fourth anniversary of the date of the loan. Interest is payable annually upon each anniversary date of this loan. At any time Isramco can make prepayments without premium or penalty. The loan is not secured. Interest is payable at the end of each loan year. Principal plus any accrued and unpaid interest are due and payable on February 27, 2014. Interest after the maturity date accrues at the per annum rate of LIBOR plus 12% until paid in full. At any time, Isramco is entitled to prepay the outstanding amount of the loan without penalty or prepayment. To secure its obligations that may be incurred under the Loan Agreement, Jay Petroleum, LLC, a wholly owned subsidiary of Isramco, agreed to guarantee the indebtedness. Naphtha can accelerate the loan and exercise its rights under the collateral upon the occurrence any one or more of the following events of default: (i) Isramco's failure to pay any amount that may become due in connection with the loan within five (5) days of the due date (whether by extension, renewal, acceleration, maturity or otherwise) or fail to make any payment due under any hedge agreement entered into in connection with the transaction, (ii) Isramco's material breach of any of the representations or warranties made in the loan agreement or security instruments or any writing furnished pursuant thereto, (iii) Isramco's failure to observe any undertaking contained in transaction documents if such failure continues for 30 calendar days after notice, (iv) Isramco's insolvency or liquidation or a bankruptcy event or (v) Isramco's criminal indictment or conviction under any law pursuant to which such indictment or conviction can lead to a forfeiture by Isramco of any of the properties securing the loan.

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Effective February 1, 2009, the loan from Naphtha to the Company was amended and restated to extend all payment deadlines arising on and after February 2009, by two years.

On March 1, 2013, the terms of the existing loan and note between the Company and Naphtha was amended extending the maturity to December 31, 2018. The payment schedule was changed on the Naphtha loan and note to require interest only payments December 31, 2013, December 31, 2014, December 31, 2015, December 31, 2016, December 31, 2017 and the final interest payment December 31, 2018 with principal outstanding paid in four equal installments with the first payment December 31, 2015 and a similar payment made December 31 in each of the following three years until the final payment on December 31, 2018. The other terms of the loan agreement and note remained unchanged. In accordance with the amendment, as of December 31, 2013 the loan is classified as long-term on our balance sheet.

Mr. Haim Tsuff, Isramco's Chief Executive Officer and Chairman and is a controlling shareholder of Naphtha.

Jerusalem Oil Exploration Ltd ("JOEL")

In February and March, 2008 the Company obtained loans from JOEL in the aggregate principal amount of \$48.9 million, repayable at the end of 4 months at an interest rate of LIBOR plus 1.25% per annum. Pursuant to a loan agreement signed in June 2009, the maturity date of this loan was extended for an additional period of seven years. Interest accrues at a per annum rate of LIBOR plus 6%. Principal and interest are due and payable in four equal annual installments, commencing on June 30, 2013. At any time, we can make prepayments without premium or penalty.

On June 30, 2013, the terms of an Amended and Restated Loan Agreement dated May 25, 2008, and note between the Company and Jerusalem Oil Exploration, Ltd. ("JOEL") were amended to extend the maturity date to June 30, 2017. The payment schedule of the loan agreement and note was amended to require principal and accrued interest to be paid in three (3) installments in the amounts reflected in Promissory Note due on June 30th of each year commencing June 30, 2015. The other terms of the loan agreement and note remained unchanged. In accordance with the amendment, as of December 31, 2013, the loans are classified as long-term on our consolidated balance sheets.

The Company evaluated the application of ASC 470-50 "Debt Modification and Extinguishment" and ASC 470-60 "Troubled Debt Restructuring" and concluded that the revised terms constituted a debt modification, rather than a debt extinguishment or a troubled debt restructuring.

Isramco also had related party payables of \$354,000 and \$328,000 as of December 31, 2013 and 2012 respectively which are included with short term related party debt on the balance sheet.

Mr. Jakob Maimon, Isramco's president at the time and a former director of the Company is a director of JOEL. Mr. Haim Tsuff, Isramco's Chief Executive Officer and Chairman, is a controlling shareholder of JOEL.

Debt Maturities

Aggregate maturities of long-term debt and accrued interest at December 31, 2013 are due in future years as follows (in thousands):

2014	14,921
2015	23,442
2016	29,364
2017	29,364
2018	13,865

Total \$ 110,956

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Interest Expense

The following table summarizes the amounts included in interest expense for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Current debt, long-term debt and other - banks	\$ -	\$ 245	\$ 1,323
Long-term debt – related parties	6,528	6,094	6,437
	\$ 6,528	\$ 6,339	\$ 7,760

6. Fair Value of Financial Instruments

Pursuant to ASC 820, Fair Value Measurements and Disclosures (ASC 820) the Company's determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's consolidated balance sheets, but also the impact of the Company's nonperformance risk on its own liabilities. ASC 820 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs.

There were no financial instruments owned at December 31, 2013 and 2012.

The Company records the net change in the fair value of these positions in “Net gain (loss) on derivative contracts” in the Company’s consolidated statements of operations, in case of commodity derivatives, and in “Other comprehensive income”, in case of interest rate derivatives. The Company is able to value these assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curve for commodity prices based on quoted market prices and prospective volatility factors related to changes in the forward curves.

As of December 31, 2011, the Company’s derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, while no assurance to this effect can be provided, the Company does not anticipate such nonperformance. Each of the counterparties to the Company’s derivative contracts is a lender in the Company’s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreements.

As of December 31, 2013 and 2012 there were no outstanding derivative contracts.

7. Income Taxes

Isramco operates through its various subsidiaries in the United States (“U.S.”); accordingly, income taxes have been provided based upon the tax laws and federal and state income tax rates in the U.S. as they apply to Isramco’s current ownership structure.

Isramco accounts for income taxes pursuant to Accounting Standards Codification (ASC) 740, Accounting for Income Taxes, which requires recognition of deferred income tax liabilities and assets for the expected future tax consequences of events that have been recognized in Isramco’s financial statements or tax returns. Isramco provides for deferred taxes on temporary differences between the financial statements and tax bases of its assets using the enacted tax rates that are expected to apply to taxable income when the temporary differences are expected to reverse.

Isramco adopted Accounting Standards Codification (ASC) 740-10, effective January 1, 2007. Isramco recognizes interest and penalties related to unrecognized tax benefits within the provision for income taxes on continuing operations. There were no unrecognized tax benefits that if recognized would affect the tax rate. There were no interest or penalties recognized as of the date of adoption or for the twelve months ended December 31, 2013. The Company's tax years subsequent to 2007 are currently remain open and subject to examination by federal tax authorities and the tax authorities in Louisiana, New Mexico, Oklahoma and Texas, which are the jurisdictions in which the Company has had its principal operations. In certain of these jurisdictions, the Company operates through more than one legal entity, each of which may have different open years subject to examination. It is important to note that years are technically open for examination until the statute of limitations in each respective jurisdiction expires.

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The income tax provision differs from the amount of income tax determined by applying the Federal Income Tax Rate to pre-tax income from continuing operations due to the following items:

	Years Ended December 31,		
	2013	2012	2011
	(In thousands)		
Expected tax (benefit) expense	\$ (3,479)	\$ 1,161	\$ 3,975
State income taxes, net	-	-	-
Foreign income taxes	-	-	-
Other	(137)	(66)	-
Total tax expense (benefit)	\$ (3,616)	\$ 1,095	\$ 3,975

Deferred tax assets at December 31, 2013 and 2012 are comprised primarily of net operating loss carry forwards and book impairment from write downs of assets. Deferred tax liabilities consist primarily of the difference between book and tax basis depreciation, depletion and amortization (DD&A) and impairment. Book basis in excess of tax basis for oil and gas properties and equipment primarily results from differing methodologies for recording property costs and depreciation, depletion and amortization under accounting principles generally accepted in the United States and the applicable income tax statutes and regulations in the jurisdictions in which the Company operates. There is a net deferred tax asset and it is management's opinion that a valuation allowance is not needed, as it is more likely than not based on objective evidence that realization of the deferred tax assets is reasonably assured.

The principal components of Isramco's deferred tax assets and liabilities as of December 31 were as follows (in thousands):

	2013	2012
Deferred current tax assets:		
Accrued interest	\$ 6,336	\$ -
Allowance for doubtful accounts	203	4,160
Deferred current tax assets	\$ 6,539	\$ 4,160
Net current deferred tax assets	\$ 6,539	\$ 4,160
Deferred noncurrent tax assets:		
Foreign tax withheld (1)	3,956	-
Net operating loss carry-forwards	10,672	13,364
Deferred noncurrent tax assets	\$ 14,628	\$ 13,364
Deferred noncurrent tax liabilities:		
Book-tax differences in property basis	(5,476)	(9,405)
Deferred noncurrent tax liabilities	\$ (5,476)	\$ (9,405)
Net noncurrent deferred tax assets	\$ 9,152	\$ 3,959

(1) Total revenues net of marketing and transportation expenses from Tamar Field were \$15,824,000. The Israeli Tax Authority withheld \$3,956,000, of this revenue which is recognized as an asset on the Company's consolidated balance sheets.

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The principal components of Isramco's Income Tax Provision for the years indicated below were as follows (in thousands):

	2013	2012	2011
Current income tax:			
Federal	\$ -	\$ -	\$ -
Foreign	-	-	-
State	-	-	-
Total current income tax	\$ -	\$ -	\$ -
Deferred income tax			
Federal	\$ (3,616)	\$ 1,095	\$ 3,975
Foreign	-	-	-
State	-	-	-
Total deferred income tax	\$ (3,616)	\$ 1,095	\$ 3,975
Provision for income tax	\$ (3,616)	\$ 1,095	\$ 3,975

At December 31, 2013 the Company has U.S. tax loss carry forwards of approximately \$30,490,000 which will expire in various amounts beginning in 2023 and ending in 2032. Utilization of such loss carry forwards could be limited to the extent Isramco has an ownership change that triggers the limitation under Section 382 of Internal Revenue Code of 1986, as amended.

8. Earnings Per Share

The following table sets forth the computation of Net Income (Loss) Per Share Available to Common Stockholders for the years ended December 31 (in thousands, except per share data):

	2013	2012	2011
Numerator for Basic and Diluted Earnings per Share -			
Net Income (loss)	\$ (6,710)	\$ 2,221	\$ 7,381
Denominator for Basic Earnings per Share -			
Weighted Average Shares	2,717,691	2,717,691	2,717,691
Potential Dilutive Common Shares -	-	-	-
Adjusted Weighted Average Shares	2,717,691	2,717,691	2,717,691
Net Income (Loss) Per Share Available to Common Stockholders – Basic			
	\$ (2.47)	\$ 0.82	\$ 2.72
Net Income (Loss) Per Share Available to Common Stockholders – Diluted			
	\$ (2.47)	\$ 0.82	\$ 2.72

9. Stock Options

The 1993 Stock Option Plan (the 1993 Plan) was approved at the annual meeting of shareholders held in August 1993. As of December 31, 2009, 20,050 shares of common stock were reserved for issuance under the 1993 Plan. Options granted under the 1993 Plan may be either incentive stock options under the Internal Revenue Code or options that do not qualify as incentive stock options. Options granted under the 1993 Plan may be exercised for a period of up to ten years from the grant date. The exercise price for an incentive stock option may not be less than 100% of the fair market value of Isramco's common stock on the date of grant. All the options granted under the 1993 Plan to date were fully vested on the date of grant. The administrator of the 1993 Plan may set the exercise price for a nonqualified stock option at less than 100% of the fair market value of Isramco's common stock on the date of grant.

No stock options were granted during 2013, 2012 and 2011. Shares of common stock reserved for future issuance under the 1993 plan are 20,050 shares. There are no granted stock options outstanding under the 1993 Plan as of balance sheet date.

At the Annual Shareholders Meeting in 2011, the shareholders adopted the 2011 Stock Incentive Plan. That plan will be administered by the Compensation Committee of the Board of Directors and there are 200,000 shares under that plan that may be awarded. Independent members of the board of directors as well as employee of and consultants to the Company are eligible to receive awards. The awards can be in the form of stock options, restricted stock or other stock-based awards. The awards are intended to qualify as performance-based compensation for purposes of Section 162(m) of the Internal Revenue Code. There are no granted awards outstanding under the 2011 Stock Incentive Plan.

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10. Supplemental Cash Flow Information

Cash paid for interest and income taxes was as follows for the years ended December 31 (in thousands):

	2013	2012	2011
Interest	\$ -	\$ 2,176	\$ 6,723
Income taxes	\$ -	\$ -	\$ -

The consolidated statements of cash flows for the years ended December 31, 2013, 2012 and 2011 exclude the following non-cash transactions:

- Property and equipment of \$2,775,000 included in accounts payable in 2013.
- Insurance premiums financed through issuance of short term debt of \$936,000 in 2013
- Accrued interest of \$1,840,000 included as part of the loan from related party that was amended on June 30, 2013.
- Property and equipment of \$778,000 included in accounts payable in 2012
- Net unrealized loss on available for sale marketable securities of \$2,254,000, net of taxes of \$1,214,000 in 2012
- Property and equipment of \$484,000 included in accounts payable in 2011
- Net unrealized loss on available for sale marketable securities of \$7,397,000, net of taxes of \$3,983,000 in 2011

11. Concentrations of Credit Risk

Financial instruments, which potentially expose Isramco to concentrations of credit risk, consist primarily of cash equivalents, trade and joint interest accounts receivable. Isramco's customer base includes several of the major United States oil and gas operating and production companies as well as major power companies in Israel. Although Isramco is directly affected by the well-being of the oil and gas production industry, management does not believe a significant credit risk existed as of December 31, 2013. Isramco continues to monitor and review credit exposure of its marketing counter-parties.

Our well service segment customers include major oil and natural gas production companies and independent oil and natural gas production companies. We perform ongoing credit evaluations of our customers and usually do not require material collateral. We maintain reserves for potential credit losses when necessary. Our results of operations and financial position should be considered in light of the fluctuations in demand experienced by oilfield service companies as changes in oil and gas producers' expenditures and budgets occur. These fluctuations can impact our results of operations and financial position as supply and demand factors directly affect utilization and hours which are the primary determinants of our net cash provided by operating activities.

Isramco maintains deposits in banks, which may exceed the amount of federal deposit insurance available. Management periodically assesses the financial condition of the institutions and believes that any possible deposit loss is minimal.

12. Segment Information

Isramco's primary business segments are vertically integrated within the oil and gas industry. These segments are separately managed due to distinct operational differences, unique technology, distribution and marketing requirements. The Company's two reporting segments are oil and gas exploration and production and well service. The oil and gas exploration and production segment explores for and produces natural gas, crude oil, condensate, and NGLs. The well service segment is engaged in rig-based and workover services, well completion and recompletion services, plugging and abandonment of wells and other ancillary oilfield services.

Oil and Gas Exploration and Production Segment

Our Oil and Gas segment is engaged in the exploration, development and production of oil and natural gas properties located onshore in the United States and ownership of various royalty interests in oil and gas concessions located offshore Israel. We own varying working interests in oil and gas wells in Louisiana, Texas, New Mexico, Oklahoma, Wyoming, Utah and Colorado and currently serve as operator of approximately 589 producing wells located mainly in Texas in New Mexico.

Production Service Segment

Our rig-based services include the completion of newly drilled wells, workover and recompletion of existing oil and natural gas wells, well maintenance, and the plugging and abandonment of wells at the end of their useful lives.

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The completion and recompletion services provided by our rigs prepare a newly drilled well, or a well that was recently extended through a workover, for production. The completion process may involve selectively perforating the well casing to access production zones, stimulating and testing these zones, and installing tubular and downhole equipment. We typically provide a well service rig and may also provide other equipment to assist in the completion process. The completion process usually takes a few days to several weeks, depending on the nature of the completion.

The workover services that we provide are designed to enhance the production of existing wells and generally are more complex and time consuming than normal maintenance services. Workover services can include deepening or extending wellbores into new formations by drilling horizontal or lateral wellbores, sealing off depleted production zones and accessing previously bypassed production zones, converting former production wells into injection wells for enhanced recovery operations and conducting major subsurface repairs due to equipment failures. Workover services may last from a few days to several weeks, depending on the complexity of the workover.

12. Segment Information (Continuing)

The maintenance services that we provide with our rig fleet are generally required throughout the life cycle of an oil or natural gas well. Examples of these maintenance services include routine mechanical repairs to the pumps, tubing and other equipment, removing debris and formation material from wellbores, and pulling the rods and other downhole equipment from wellbores to identify and resolve production problems. Maintenance services generally take less than 48 hours to complete. Our rig fleet is also used in the process of permanently shutting-in oil or natural gas wells that are at the end of their productive lives. These plugging and abandonment services generally require auxiliary equipment in addition to a well servicing rig. The demand for plugging and abandonment services is not significantly impacted by the demand for oil and natural gas because well operators are required by state and federal regulations to plug wells that are no longer productive.

thousands	Oil and Gas Exploration & Production	Well Service	Eliminations	Total
Year Ended December 31, 2013:				
Sales revenues				
United States	\$ 35,464	\$ 16,294	\$ -	\$ 51,758
Non-U.S.	15,824	-	-	15,824
Intersegment revenues	-	2,265	(2,265)	-
Office services and other	1,230	-	(120)	1,110
Total revenues and other	52,518	18,559	(2,385)	68,692
Operating costs and expenses				
Operating costs and expenses	59,355	15,051	(2,385)	72,021
Interest expenses, net and other	4,942	1,586	-	6,528
Other income, net	89	(6)		83
Total expenses and other	64,386	16,631	(2,385)	78,632
Income (loss) before income taxes	\$ (11,868)	\$ 1,928	\$ -	\$ (9,940)
Net income (loss)	(7,713)	1,389	-	(6,324)
Net income attributable to noncontrolling interests	-	386	-	386
Net income (loss) attributable to Isramco	(7,713)	1,003	-	(6,710)
Total Assets	\$ 116,137	\$ 41,776	\$ -	\$ 157,913

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thousands	Oil and Gas Exploration & Production	Well Service	Eliminations	Total
Year Ended December 31, 2012:				
Sales revenues				
United States	\$ 40,402	\$ 9,279	\$ -	\$ 49,681
Non-U.S.	-	-	-	-
Intersegment revenues	-	1,581	(1,581)	-
Office services and other	869	-	(120)	749
Total revenues and other	41,271	10,860	(1,701)	50,430
Operating costs and expenses				
Operating costs and expenses	37,222	8,912	(1,701)	44,433
Net gain on derivatives, contracts	(219)	-	-	(219)
Realized gain on marketable securities	(3,650)	-	-	(3,650)
Interest expenses, net and other	5,508	816	-	6,324
Total expenses and other	38,861	9,728	(1,701)	46,888
Income before income taxes	\$ 2,410	\$ 1,132	\$ -	\$ 3,542
Net Income	1,632	815	-	2,447
Net income attributable to noncontrolling interests	-	226	-	226
Net Income attributable to Isramco	1,632	589	-	2,221
Total Assets	\$ 132,140	\$ 21,818	\$ -	\$ 153,958

13. Commitments and Contingencies

Commitments

Isramco has a few immaterial lease agreements.

Contingencies

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued based on the Company's best estimate of the potential loss. In the opinion of management, Isramco's ultimate liability, if any, in these pending actions would not have a material adverse effect on the financial position, operating results or liquidity of Isramco.

14. Asset Retirement Obligation

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, the Company records a liability (an asset retirement obligation or ARO) on the consolidated balance sheet and capitalizes the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

The following table presents the reconciliation of the beginning and ending aggregate carrying amount legal obligations associated with the retirement of oil and gas properties at December 31 (in thousands):

	2013	2012	2011
Liability for asset retirement obligation at the beginning of the year	\$ 17,908	\$ 17,250	\$ 16,577
Liabilities Incurred	35	19	62
Liabilities settled and divested	(31)	(236)	(242)
Accretion expense	902	875	853
Liability for asset retirement obligation at the end of the year	\$ 18,814	\$ 17,908	\$ 17,250

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15. Supplemental Oil and Gas Information (Unaudited)

The following supplemental information regarding the oil and gas activities of Isramco for 2013, 2012 and 2011 is presented pursuant to the disclosure requirements promulgated by the Securities and Exchange Commission and SFAS No. 69, "Disclosures About Oil and Gas Producing Activities." Capitalized costs relating to oil and gas activities and costs incurred in oil and gas property acquisition, exploration and development activities for each year are shown below.

CAPITALIZED COST OF OIL AND GAS PRODUCING ACTIVITIES (IN THOUSANDS)

As of December 31	2013		2012	
	United States		United States	
Unproved properties not being amortized	\$	-	\$	-
Proved property being amortized		236,399		231,327
Accumulated depreciation, depletion amortization and impairment		(149,902)		(116,321)
Net capitalized costs		86,497		115,006

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION, AND DEVELOPMENT ACTIVITIES (IN THOUSANDS)

As of December 31	2013		2012		2011	
Property acquisition costs—proved and unproved properties	\$	74	\$	-	\$	151
Exploration costs	\$	-	\$	-	\$	-
Development costs	\$	4,964	\$	5,422	\$	2,398

OIL AND GAS RESERVES

Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Economic producibility of reserves is dependent on the crude oil and natural gas prices used in the reserves estimate. We based our December 31, 2013, 2012, and 2011 reserves estimates on 12-month average commodity prices, unless contractual arrangements designate the price to be used, in accordance with SEC rules. However, commodity prices are volatile. Declines in crude oil or natural gas prices could result in negative reserves revisions.

The following definitions apply to our categories of proved reserves:

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.

Developed Oil and Gas Reserves Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well.

Undeveloped Oil and Gas Reserves Proved undeveloped oil and gas reserves (PUDs) are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. 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.

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For complete definitions of proved natural gas, natural gas liquids and crude oil reserves, refer to SEC Regulation S-X, Rule 4-10(a)(6), (22) and (31).

Geographic Areas

Our supplemental disclosures are grouped by geographic area, which include the United States and Israel.

The following table illustrates the Company's estimated net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc and Cawley, Gillespie & Associates, Inc.

	Oil Bbls			Gas Mcf		
	United States	Israel	Total	United States	Israel	Total
December 31, 2010	3,317,923	-	3,317,923	23,700,905	-	23,700,905
Revisions of previous estimates	180,104	-	180,104	3,573,698	-	3,573,698
Extensions, discoveries, and other additions	15,033	-	15,033	21,847	154,100,000	154,121,847
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(278,601)	-	(278,601)	(2,241,384)	-	(2,241,384)
December 31, 2011	3,234,459	-	3,234,459	25,055,066	154,100,000	179,155,066
Revisions of previous estimates	270,970	-	270,970	(1,950,030)	11,768,963	9,818,933
Extensions, discoveries, and other additions	25,040	-	25,040	22,883	-	22,883
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(297,506)	-	(297,506)	(2,159,311)	-	(2,159,311)
	3,232,963	-	3,232,963	20,968,608		

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December 31, 2012					165,868,963	186,837,571
Revisions of previous estimates	(139,100)	-	(139,100)	464,987	36,128,550	36,593,537
Extensions, discoveries, and other additions	37,457	-	37,457	55,191	-	55,191
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(257,785)	-	(257,785)	(1,798,661)	(2,736,000)	(4,534,661)
December 31, 2013	2,873,535	-	2,873,535	19,690,125	199,261,513	218,951,638
Proved Developed Reserves						
December 31, 2013	2,873,535	-	2,873,535	19,690,125	199,261,513	218,951,638
December 31, 2012	3,232,963	-	3,232,963	20,968,608	-	20,968,608
December 31, 2011	3,234,459	-	3,234,459	25,055,066	-	25,055,066
December 31, 2010	3,317,923	-	3,317,923	23,700,905	-	23,700,905
Proved Undeveloped Reserves						
December 31, 2013	-	-	-	-	-	-
December 31, 2012	-	-	-	-	165,868,963	165,868,963
December 31, 2011	-	-	-	-	154,100,000	154,100,000
December 31, 2010	-	-	-	-	-	-
December 31, 2009	-	-	-	-	-	-

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	NGL Bbls			Total MBOE		
	United States	Israel	Total	United States	Israel	Total
December 31, 2010	1,763,150	-	1,763,150	9,031,224	-	9,031,224
Revisions of previous estimates	265,863	-	265,863	1,041,583	-	1,041,583
Extensions, discoveries, and other additions	3,897	-	3,897	22,571	25,683,333	25,705,904
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(136,446)	-	(136,446)	(788,611)	-	(788,611)
December 31, 2011	1,896,464	-	1,896,464	9,306,767	25,683,333	34,990,100
Revisions of previous estimates	(93,043)	218,572	125,529	(147,078)	2,180,066	2,032,988
Extensions, discoveries, and other additions	4,763	-	4,763	33,617	-	33,617
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(133,588)	-	(133,588)	(790,979)	-	(790,979)
December 31, 2012	1,674,596	218,572	1,893,168	8,402,327	27,863,399	36,265,726
Revisions of previous estimates	(98,276)	44,265	(54,020)	(159,878)	6,065,681	5,905,803
Extensions, discoveries, and other additions	-	-	-	46,656	-	46,656
Acquisition of minerals in place	-	-	-	-	-	-
Sales of minerals in place	-	-	-	-	-	-
Production	(113,922)	(3,788)	(117,710)	(671,484)	(459,788)	(1,131,272)
December 31, 2013	1,462,398	259,040	1,721,438	7,617,621	33,469,292	41,086,913
Proved Developed Reserves	1,462,398	259,040	1,721,438	7,617,621	33,469,292	41,086,913

December 31, 2013						
December 31, 2012	1,674,596	-	1,674,596	8,402,327	-	8,402,327
December 31, 2011	1,896,464	-	1,896,464	9,306,767	-	9,306,767
December 31, 2010	1,763,150	-	1,763,150	9,031,224	-	9,031,224

Proved
Undeveloped
Reserves

December 31, 2013	-	-	-	-	-	-
December 31, 2012	-	218,572	218,572	-	27,863,399	27,863,399
December 31, 2011	-	-	-	-	25,683,333	25,683,333
December 31, 2010	-	-	-	-	-	-
December 31, 2009	-	-	-	-	-	-

(1) Gas reserves are converted to BOE at the rate of six Mcf per Bbl of oil, based upon the approximate relative energy content of gas and oil. This rate is not necessarily indicative of the relationship of natural gas and oil prices. Natural gas liquids reserves are converted to BOE on a one-to-one basis with oil.

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Extensions, discoveries, and other additions —

The 2011 increase in Israel is due to the recording of reserves at the Tamar development offshore Israel.

The increase in 2013 and 2012 of the United State reserves is from development of onshore assets, primarily in the Permian Basin

Revisions of Previous Estimates —

2011 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The upward Revisions of Previous Estimates was due to significantly higher average first-day of the month oil gas and NGLs prices calculated for the 12 months ended December 31, 2011 compared to prices as of December 31, 2010.

2012 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The United State downward Revisions of Previous Estimates was due to significantly lower average first-day of the month natural gas and NGLs prices calculated for the 12 months ended December 31, 2012 compared to prices as of December 31, 2011. The Israel upward Revisions of Previous Estimates were due to information that became available regarding our proved reserves. Also, this new information has allowed us to predict better our future economical sales.

2013 — Proved reserves must be estimated using the assumption that prices and costs remain constant for the duration of the reservoir life. The United State downward Revisions of Previous Estimates was due to significantly lower average first-day of the month NGLs prices calculated for the 12 months ended December 31, 2013 compared to prices as of December 31, 2012; decreased production volumes and increased production costs associated with operations in several of our leases.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOW

The following Standardized Measure of Discounted Future Net Cash Flow information has been developed utilizing ASC 932, Extractive Activities —Oil and Gas, (ASC 932) procedures and based on oil and natural gas reserve and production volumes estimated by our independent reserve engineering firms, Netherland, Sewell & Associates, Inc and Cawley, Gillespie & Associates, Inc. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flow be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- future costs and selling prices will probably differ from those required to be used in these calculations;
- due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;
- a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and

- future net revenues may be subject to different rates of income taxation.

Results of operations from producing activities were as follows for the years ended December 31:

	2013	2012	2011
	(in thousands)		
Production revenues	\$ 51,288	\$ 40,402	\$ 44,228
Production costs	19,974	19,737	20,981
Depreciation, depletion, amortization and accretion	11,568	11,513	10,747
Impairment of oil and natural gas properties	23,161	1,225	4,034
Loss from plug and abandonment	226	314	315
Results of operations from producing activities	\$ (3,641)	\$ 7,613	\$ 8,151

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Estimates of future net cash flows from proved reserves of natural gas, oil, condensate, and NGLs for 2013, 2013, and 2011 are computed using the average first-day-of-the-month price during the 12-month period for the respective year. Prices used to compute the information presented in the tables below are adjusted only for fixed and determinable amounts under provisions in existing contracts. Estimated future net cash flows for all periods presented are reduced by estimated future development and production based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development and production costs. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by U.S. Generally Accepted Accounting Principles.

millions	United States	Israel	Total
December 31, 2013			
Future cash inflows (4)	\$ 397,415,044	\$ 1,174,562,935	\$ 1,571,977,979
Future development costs	(875,854)	-	(875,854)
Future production costs (3)	(189,353,937)	(372,384,334)	(561,738,271)
Future income tax expenses	(32,401,565)	(244,317,856)	(276,719,421)
Future net cash flows	174,783,688	557,860,745	732,644,433
10% annual discount for estimated timing of cash flows	(81,017,433)	(296,671,675)	(377,689,108)
Standardized measure of discounted future net cash flows	\$ 93,766,255	\$ 261,189,070	\$ 354,955,325
December 31, 2012			
Future cash inflows (1)	\$ 437,039,898	\$ 952,661,027	\$ 1,389,700,925
Future development costs	(875,854)	-	(875,854)
Future production costs (3)	(216,179,970)	(297,357,515)	(216,179,970)
Future income tax expenses	(44,027,403)	(223,707,032)	(565,091,950)
Future net cash flows	175,956,671	431,596,480	607,553,151
10% annual discount for estimated timing of cash flows	(80,143,273)	(229,293,981)	(309,437,254)
Standardized measure of discounted future net cash flows	\$ 95,813,398	\$ 202,302,499	\$ 298,115,897
December 31, 2011			
Future cash inflows (2)	\$ 506,668,204	\$ 634,462,200	\$ 1,141,130,404
Future development costs	(875,854)	-	(875,854)
Future production costs (3)	(240,176,108)	(183,863,777)	(240,176,108)
Future income tax expenses	(45,477,986)	(157,709,446)	(387,051,209)
Future net cash flows	220,138,256	292,888,977	513,027,233
10% annual discount for estimated timing of cash flows	(107,734,348)	(168,565,572)	(276,299,920)
Standardized measure of discounted future net cash flows	\$ 112,403,908	\$ 124,323,405	\$ 236,727,313

(1)

The increase in expected cash flow from Israel is primarily due to the increase in natural gas prices stated in the contracts with our customers. It is uncertain that all of the expected production would be sold according to these contracts and stated prices.

- (2) The increase in Israel is due to the recording of reserves at the Tamar development offshore Israel.
- (3) The government of Israel imposes a tax or charge upon oil and gas revenues, including revenues from oil and gas produced from the Tamar well. Currently, such oil and gas revenues would be subject to a sliding scale of taxation, beginning with the imposition of a 20% charge on oil and gas revenues at such time as total revenues received equal 1.5 times the costs expended and increasing in steps to a 45.5% charge imposed at such time as revenues received equal 1.5 times the costs expended. The current tax law provides some relief for oil and gas revenues received from reservoirs developed before January 2014 by delaying the imposition of the charges; i.e. the 20% charge would become effective at such time as total revenues received equal 2 times the costs expended and the maximum 45.5% charge would not become effective until revenues received equaled 2.8 times costs expended. Isramco's overriding royalty would be subject to the above taxation at such time, and at the same rates, as the revenues attributable to the operating interest. The imposed Israeli tax is included in calculation of future gas revenues from Tamar Field.
- (4) The increase in future cashflows is associated with increase in Tamar Field reserves. The increase in reserves was due to revision of estimates based on new and more reliable information as well as increase in estimated sales prices based on the contracts with customers.

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CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

The following is a summary of the changes in the Standardized Measure of discounted future net cash flows for the Company's proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2013

Changes in Standardized Measure of Discounted Future Net Cash Flows
Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2013			
Balance at January 1	\$ 95,813,398	\$ 202,302,499	\$ 298,115,897
Sales and transfers of oil and gas produced, net of production costs	(15,485,290)	-	(15,485,290)
Net changes in prices and production costs	3,294,058	9,920,752	13,214,810
Changes in estimated future development costs, net of current development costs	(1,433,453)	-	(1,433,453)
Extensions, discoveries, additions, and improved recovery, less related costs	1,489,283	-	1,489,283
Development costs incurred during the period			
Revisions of previous quantity estimates	(165,616)	85,289,673	85,124,057
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	9,586,148	33,123,175	42,709,323
Net change in income taxes	11,094,190	14,004,812	25,099,002
Change in production rates and other	(10,426,463)	(83,451,841)	(93,878,304)
Balance at December 31	\$ 93,766,255	\$ 261,189,070	\$ 354,955,325
2012			
Balance at January 1	\$ 112,288,045	\$ 124,323,405	\$ 236,611,450
Sales and transfers of oil and gas produced, net of production costs	(20,665,788)	-	(20,665,788)
Net changes in prices and production costs	(9,532,899)	95,058,438	85,525,539
Changes in estimated future development costs, net of current development costs	(2,495,083)	-	(2,495,083)
Extensions, discoveries, additions, and improved recovery, less related costs	2,589,648	-	2,589,648
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates	(2,110,629)	29,078,878	26,968,249
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	12,411,678	24,173,841	36,585,519
Net change in income taxes	13,542	(57,558,963)	(57,545,421)
Change in production rates and other	3,314,884	(12,773,100)	(9,458,216)

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Balance at December 31	\$ 95,813,398	\$ 202,302,499	\$ 298,115,897
2011			
Balance at January 1	\$ 97,633,354	\$ -	\$ 97,633,354
Sales and transfers of oil and gas produced, net of production costs	(23,247,735)	-	(23,247,735)
Net changes in prices and production costs	18,142,794	-	18,142,794
Changes in estimated future development costs, net of current development costs	(1,213,256)	-	(1,213,256)
Extensions, discoveries, additions, and improved recovery, less related costs	-	124,323,405	124,323,405
Development costs incurred during the period	-	-	-
Revisions of previous quantity estimates	14,623,353	-	14,623,353
Purchases of minerals in place	-	-	-
Sales of minerals in place	-	-	-
Accretion of discount	10,476,340	-	10,476,340
Net change in income taxes	(5,726,668)	-	(5,726,668)
Change in production rates and other	1,599,863	-	1,599,863
Balance at December 31	\$ 112,288,045	\$ 124,323,405	\$ 236,611,450

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Table of ContentsUnaudited Quarterly Financial Information
(In Thousands, Except Per Share Data)

Quarter Ended	March 31	June 30	September 30	December 31
2013				
Total Revenues	\$ 11,452	\$ 17,038	\$ 19,585	\$ 20,617
Net Income (loss) before taxes	(784)	4,845	6,057	(20,058)
Net Income (loss) attributable to common shareholders	(509)	3,172	3,999	(12,986)
Net income attributable to noncontrolling interests	(1)	65	176	145
Net income (loss) attributable to Isramco	(508)	3,107	3,823	(13,132)
Earnings (loss) per share:				
Net income (loss) attributable to common stockholders - basic	\$ (0.19)	\$ 1.14	\$ 1.41	\$ (4.83)
Net income (loss) attributable to common stockholders - diluted	\$ (0.19)	\$ 1.14	\$ 1.41	\$ (4.83)
Average number common shares outstanding - basic	2,717,691	2,717,691	2,717,691	2,717,691
Average number common shares outstanding - diluted	2,717,691	2,717,691	2,717,691	2,717,691
2012				
Total Revenues	\$ 11,464	\$ 12,828	\$ 12,755	\$ 13,383
Net Income (loss) before taxes	2,371	3,934	(1,749)	(1,014)
Net Income (loss) attributable to common shareholders	1,542	2,592	(1,124)	(563)
Net income attributable to noncontrolling interests	-	102	35	89
Net income (loss) attributable to Isramco	1,542	2,490	(1,159)	(652)
Earnings (loss) per share:				
Net income (loss) attributable to common stockholders - basic	\$ 0.57	\$ 0.92	\$ (0.43)	\$ (0.24)
Net income (loss) attributable to common stockholders - diluted	\$ 0.57	\$ 0.92	\$ (0.43)	\$ (0.24)
Average number common shares outstanding - basic	2,717,691	2,717,691	2,717,691	2,717,691
Average number common shares outstanding - diluted	2,717,691	2,717,691	2,717,691	2,717,691
2011				
Total Revenues	\$ 11,150	\$ 11,747	\$ 11,177	\$ 11,574
Net Income (loss) before taxes	(6,623)	2,001	22,607	(6,624)
Net Income (loss) attributable to common shareholders	(4,306)	1,301	14,694	(4,303)
Net income attributable to noncontrolling interests	-	-	-	5
Net income (loss) attributable to Isramco	(4,306)	1,301	14,694	(4,308)
Earnings (loss) per share:				
Net income (loss) attributable to common stockholders - basic	\$ (1.58)	\$ 0.48	\$ 5.41	\$ (1.59)
	\$ (1.58)	\$ 0.48	\$ 5.41	\$ (1.59)

Net income (loss) attributable to common
stockholders - diluted

Average number common shares outstanding - basic	2,717,691	2,717,691	2,717,691	2,717,691
Average number common shares outstanding - diluted	2,717,691	2,717,691	2,717,691	2,717,691

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