PRIMA ENERGY CORP
Form 10-K
March 15, 2004

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

FORM 10-K

þ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2003.

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Commission file number 0-9408

PRIMA ENERGY CORPORATION

(Exact name of Registrant as specified in its charter)

DELAWARE	**84-1097578**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1099 18th Street, Suite 400, Denver, Colorado 80202
(Address of principal executive offices) (Zip Code)

(303) 297-2100
(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act
None

Securities registered pursuant to Section 12(g) of the Act
Common Stock, $0.015 Par Value
(Title of Class)

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

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

Indicate by checkmark whether the Registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes x No o

The aggregate market value of the 9,221,894 shares of voting stock held by non-affiliates of the Registrant, based upon the closing price of the common stock on June 30, 2003 of $20.82 per share as reported on the Nasdaq National Market, was $191,999,833. Shares of common stock held by each officer and director and by each person who owns 10% or more of the outstanding common stock have been excluded in that such persons may be deemed affiliates.

This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of February 27, 2004, Registrant had outstanding 12,964,142 shares of Common Stock, $0.015 Par Value, its only class of voting stock.

Document Incorporated by Reference

Parts of the following document are incorporated by reference to Items 10, 11, 12, 13 and 14 of Part III of the Form 10-K Report: Definitive Proxy Statement for the Registrant s 2004 Annual Meeting of Stockholders.

TABLE OF CONTENTS

Item		Page
	PART I	
1. and 2.	BUSINESS and PROPERTIES	3
	General The Company	3
	Strategy	4
	Oil and Gas Properties and Operations	6
	Oilfield Services	17
	Other Properties	17
	Competition	18
	Regulation	18
	Operating Hazards and Insurance	21
	Employees and Offices	21
	Available Information	21
	Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995	21
3.	LEGAL PROCEEDINGS	24
4.	SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	25
	PART II	
5.	MARKET FOR THE REGISTRANT S COMMON STOCK AND RELATED STOCKHOLDER MATTERS	25
6.	SELECTED FINANCIAL DATA	26
7.	MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	27
	Critical Accounting Policies and Estimates	27
	Liquidity and Capital Resources	30
	Results of Operations	32
	New Accounting Pronouncements	38
7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	38
8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	40
9.	CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	40
9A.	CONTROLS AND PROCEDURES	40
	PART III	
10.	DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT .	40

11.	EXECUTIVE COMPENSATION	40
12.	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS	40
13.	CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS	40
14.	PRINCIPAL ACCOUNTANT FEES AND SERVICES	40
	PART IV	
15.	EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K	41

Code of Ethics for Senior Financial Officers
Subsidiaries of the Registrant
Independent Auditors Consent
Independent Reservoir Engineers & Geologists
Certification of Chief Executive Officer
Certification of Chief Financial Officer
Certifications of CEO and CFO

Table of Contents

PART I

ITEMS 1 and 2. BUSINESS and PROPERTIES

References in this report to Prima, the Company, we, us or our are intended to refer to Prima Energy Corporatio its consolidated subsidiaries. This report contains numerous forward-looking statements that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These include, without limitation, statements relating to future drilling and completion of wells, well operations, production, prices, costs and expenses, cash flow, investments, utilization of oilfield service equipment, reserve estimates (including estimates for future net revenues associated with such reserves and the present value of such future net revenues), business strategies, and other plans and objectives of Prima management for future operations and activities and other such matters. The words, believes, plans, intends, estimates, projects, expects, anticipates, strategy, budgeted and simil identify forward-looking statements.

Prima does not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with Prima s disclosures under the heading: Cautionary Statement for the Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995 beginning on page 21 of this report.

General The Company

Prima was incorporated in April 1980 to engage in crude oil and natural gas related exploration, acquisition, development, production, and related business activities. In October 1980, Prima became publicly owned with a $3.6 million common stock offering. Our subsequent activities have primarily been related to oil and gas production operations, but have also included oil and gas property management, oilfield services, and, at times, natural gas gathering, marketing and trading. The substantial majority of Prima s consolidated assets and revenues continue to be related to its oil and gas production operations.

Our principal activities are currently organized into two active operating segments. The larger of these consists of the acquisition, exploration, development and operation of oil and gas properties. The second segment is comprised of oilfield service operations conducted for unaffiliated third parties and for Prima. Though at times in the past we have also been involved in oil and gas marketing and trading, and in gas gathering and compression operations, these activities were not significant during the three years ended December 31, 2003. See Note 7 of Notes to Consolidated Financial Statements included as a part of Item 8 of this Report for financial information pertaining to these industry segments.

Our oil and gas exploration, development and production operations are generally conducted within Prima Oil & Gas Company, a wholly owned subsidiary. We conduct most other activities within wholly owned subsidiaries of Prima Oil & Gas Company, including Action Oil Field Services, Inc. and Action Energy Services for oilfield services.

We have conducted our activities principally in the Rocky Mountain region of the United States. At the end of 2003, Prima owned or controlled mineral leasehold interests in over 510,000 gross, or 390,000 net, acres, predominately in the Denver-Julesburg (D-J) Basin of Colorado, the Powder River, Wind River, Big Horn and Green River Basins of Wyoming, and within the Wasatch Plateau and Overthrust Belt in Utah.

Historically, we have grown our proven oil and gas reserves and production primarily through acquiring oil and gas leaseholds and drilling wells to exploit and develop tight sand and coalbed methane (CBM) properties. Generally, the probability that such properties have hydrocarbons in place is estimated to be relatively high and the viability of establishing proved reserves is largely dependent on several factors, including: the market price for oil and gas; the costs of development, production and marketing; and determination of the amount of recoverable reserves and the rate at which such reserves can be extracted. To a lesser extent, we have added proved reserves through exploration activities and acquisition of properties with proved developed reserves. At the end of 2003, over 90% of our proved oil and gas reserves and production were associated with tight sand properties in the D-J Basin in eastern Colorado and CBM properties in the Powder River Basin in eastern Wyoming. The balance of our proved reserves and production at the end of 2003 related to properties in the Wind River Basin in central Wyoming and non-CBM wells in the Powder River Basin.

Table of Contents

We have identified more than 2,800 potential exploitation and development opportunities on our D-J Basin and Powder River Basin CBM-prospective acreage, of which 485 were assigned proved oil and gas reserves at year-end 2003. Most of the identified non-proved opportunities represent potential CBM drilling locations in the Powder River Basin, with the remainder comprised primarily of recompletion and refracturing projects and other drilling locations in the D-J Basin. This set of identified opportunities includes only those projects that we believe have the potential to be economically viable using future oil and gas prices reflected in commodity futures markets at the end of 2003. We have also developed an inventory of exploratory prospects in other areas, including the Green River Basin in western Wyoming, the Overthrust Belt in northeast Utah and the Uintah Basin in eastern Utah which could, if successfully tested, establish new areas for future exploitation and development activities.

Our oilfield service operations are presently conducted in two areas where Prima has an established base of exploitation and production operations. These are the D-J Basin and the CBM play in the Powder River Basin. Action Oilfield Services, which operates in the D-J Basin, owns various well servicing equipment including eight workover rigs, a swab rig, tractor trailer rigs for water hauling, and oilfield rental equipment, such as pumps, tanks and blowout preventers. Action Energy Services, which operates in the Powder River Basin, owns nine CBM drilling and service rigs. Our service companies provide services to both Prima and other operators, and during 2003 operations provided to unrelated parties generated approximately 12% of Prima s total consolidated revenues. While these operations have typically generated positive earnings and cash flow, and have also enabled us to exert more control over costs and the quality of work performed for some of our well operations, they have not historically constituted a significant portion of Prima s assets or operations.

The following is a brief summary of selected key financial and operating data reported by Prima at December 31, 2003:

- $177,217,000 of assets.
- $56,148,000 of net working capital (with $57,192,000 of cash and marketable securities).
- No long-term debt.
- Estimated net proved reserves of 125,796,000 Mcf of natural gas equivalents (Mcfe), with a pre-tax net present value using a 10% discount factor (PV10) of $239,800,000, based on constant year-end average price realizations of $4.95 per Mcf of natural gas and $32.88 per barrel of oil. The related after-tax standardized measure of discounted future net cash flows was $158,979,000.
- Lease holdings of approximately 473,000 gross (360,000 net) undeveloped acres and 37,000 gross (30,000 net) developed acres.
- Operations of 708 productive wells (91% of the productive wells in which we own a working interest).

For the year ended December 31, 2003, we reported the following:

- Net income of $23,795,000.
- Net cash provided by operating activities of $46,149,000.
- Average daily net production of 35,658 Mcf of natural gas and 1,099 barrels of crude oil (42,252 Mcfe).
- Average price realizations of $3.53 per Mcf of natural gas and $31.71 per barrel of crude oil.

Strategy

Objectives. We seek to create shareholder value by identifying, evaluating and capturing opportunities related to the oil and gas industry. Most of our investment activities have been, and are projected to be, associated with our exploration and production operations, including the acquisition, exploration, development, and exploitation of properties, and production of oil and gas. We have also invested and conducted operations in oilfield services, gas gathering and processing, and in oil and gas marketing and trading, and we intend to continue seeking such opportunities in the future. One of Prima s goals is to be among the lowest-cost full-cycle producers of oil and gas, and to realize among the highest cash flow margins for reinvestment, in the industry. Through our related activities in other segments of the energy business, we seek to complement and reinforce the achievement of goals in our exploration and production operations, and to enhance total returns to shareholders.

Acreage. We seek to acquire oil and gas leaseholds in prospective areas at reasonable costs and with attractive terms. We can potentially benefit from the activities of other operators in these areas as well as from our own activities.

Operations. We generally prefer to operate oil and gas properties in which we own significant economic interests. As operator, we are in a better position to control the costs, timing, quality and safety of work performed, and other factors that can affect the profitability of a property. In some instances, however, we may prefer to retain non-operating interests in properties where another operator has achieved economies of scale or has other operating advantages.

Exploitation. We intend to continue property exploitation activities in our principal operating areas. In the D-J Basin, we plan to continue well refracturing, recompletions and development drilling, to the extent warranted by ongoing results and market conditions. We also plan to continue exploitation activities targeting CBM in the Powder River Basin and conventional reservoirs in the Wind River Basin, depending upon the merits of each activity and subject to regulatory considerations. We generally assess these activities as low-to-moderate risk endeavors that can be undertaken whenever market conditions are projected to be adequate for projects to meet our investment criteria, provided we are able to obtain necessary approvals from regulatory authorities.

Exploration. We generally seek to allocate 5% to 20% of our capital expenditures budget toward higher-risk exploration activities. These activities may include leasehold acquisitions, geologic and geophysical evaluation, and drilling test wells on prospects. Our exploratory prospects can be either internally generated or result from acquiring interests in other operators prospects. The objective of our exploration activities is to expose a portion of our capital to higher-risk projects that we believe have the potential to deliver high rates of return if successful. As compared to individual exploitation opportunities, a successful exploration project could have a more significant impact on Prima s value but the likelihood of success is considerably lower.

Gathering, Marketing and Trading. We elect to market our own natural gas and crude oil production whenever we believe that we can enhance our net price realizations by doing so. At times, Prima may also own assets downstream of the wellhead, including, but not limited to, gathering and compression facilities. We invest in such downstream assets where we believe opportunities exist to enhance Prima s overall project economics by capturing an additional portion of the value chain from the wellhead to the burner tip. We may also gather, compress and market third-party gas, if we expect that project rates of return will be attractive.

Oilfield Services. We believe that we can, at times, achieve better control of the timing, quality and cost of work performed on our wells by owning and operating well servicing equipment. We also intend for these activities to constitute a separate business segment and profit center through providing such services to other operators.

Mergers, Acquisitions and Divestitures. We regularly review merger, acquisition and divestiture opportunities related to the oil and gas industry that could complement or enhance Prima s existing businesses. We intend to pursue, and if possible consummate, such transactions when we believe that they would improve the risk-adjusted returns realized by Prima s shareholders over the long term.

Derivatives. We periodically use commodity futures contracts to mitigate the impact of the volatility of oil and gas prices on a portion of our production and gas marketing activities. Our use of such derivatives is also intended to improve our average oil and gas price realizations over time, to enhance profitability, though such outcome cannot be assured. We may also elect at times to enter into derivatives contracts for volumes that exceed our projected total production, or which increase, rather than decrease, our exposure to a decline in oil and gas prices or expansion of basis differentials. We would consider establishing such positions if our analyses lead us to believe that prices are likely to move in a manner that would generate gains from the positions. Derivative positions for volumes greater than our expected production, or which would increase our exposure to a decline in oil and gas prices or expansion of basis differentials, would be speculative and would be limited in size to an amount that, in management s judgment would not be material to our balance sheet taken as a whole, but they might have a significant positive or negative impact on reported net earnings.

Oil and Gas Properties and Operations

Major Properties

Denver-Julesburg Basin

This basin has been under extensive development since the 1970 s and has been substantially drilled. However, continued development has been supported by improvements in fracturing (or frac) technology to enhance oil and gas recoveries from tight sand reservoirs and by higher oil and gas prices. Because of the additional drilling and well stimulations encouraged by these factors, the D-J Basin continues to be under very active development and basin-wide production is near all-time peak levels.

Our activities in the D-J Basin have been conducted primarily in the Wattenberg Area, which encompasses more than 1,000 square miles, between 20 and 55 miles northeast of Denver, Colorado. We have conducted operations in the D-J basin for more than 20 years, and at the end of 2003 we owned working interests in 455 wells in the area, 436 of which we operated. Our drilling and production activities to date in the D-J Basin have been centered in a portion of the Wattenberg Field where the primary productive reservoirs are found in the Codell and Niobrara formations, which blanket large areas of the field at depths of approximately 7,000 to 7,300 feet. These formations have moderate porosity and low permeability, and require fracture stimulation to establish economic production. Recoverable reserves from any individual wellbore are largely dependent on reservoir quality, sand thickness, and fracture stimulation techniques.

Our D-J Basin wells produce both natural gas and crude oil. Prima s natural gas production in this area averages approximately 1,240 Btu per Mcf at the wellhead. Natural gas liquids (propane, butane, ethane, isobutane, and pentane) are extracted from the well stream and sold separately by third-party gatherer/purchasers but their value is reflected in our wellhead price for natural gas. Our average gas price realizations per Mcf in this area have ordinarily slightly exceeded Rocky Mountain spot prices due to the high Btu content of the gas, but this relationship varies with market conditions and is dependent, in part, on the price levels of natural gas liquids. In 2003, our gas price realizations for D-J Basin production averaged $4.13 per Mcf, compared to the Colorado Interstate Gas (CIG) index average of $4.04 per MMBtu. Our crude oil in this area is sweet and generally commands a price comparable to oil traded on the New York Mercantile Exchange (NYMEX).

Prima s leasehold position in the D-J Basin at the end of 2003 included 19,110 gross (16,570 net) developed acres, and an additional 12,000 gross (11,000 net) undeveloped acres. Our estimated proved reserves in the D-J Basin at that date were approximately 53,753,000 Mcf of natural gas and 4,892,000 barrels of oil, or 83,105,000 Mcfe, representing 66% of our total estimated proved reserve quantities. During 2003, Prima s net production from D-J Basin properties averaged approximately 14,700 Mcf of gas and 1,065 barrels of oil, or 21,100 Mcfe, per day, accounting for 50% of our total oil and gas production and 59% of our oil and gas sales revenues (excluding hedging effects). Our net production from D-J Basin wells was less than 1% lower in 2003 than in 2002, reflecting roughly offsetting effects of natural depletion and new activities.

Codell/Niobrara wells that we recently drilled and completed in this area have generally cost approximately $285,000 and targeted approximately 200,000 to 250,000 Mcfe of gross recoverable reserves per well (excluding refracs, discussed below). At year-end 2003, we controlled approximately 200 potential drill sites in the D-J Basin, with 90 of these attributed proved undeveloped reserves. These proved locations have projected rates of return above 35% using futures prices reflected on forward markets on December 31, 2003. During 2003, we drilled 28 gross (27.0 net) wells in the D-J Basin, all of which were successfully completed and placed on production.

Advancements in refracturing (refrac) stimulation technology have enabled us to add deliverability and reserves from the Codell and Niobrara formations. A refrac is a procedure in which a formation in an older well that has been

Table of Contents

previously fractured at least once is stimulated by another fracture treatment. We generally target older wells with declining deliverability for restimulation. Prima performed 38 refracs in Wattenberg during 2003, with such activities primarily focused on the Codell formation. These had an average cost of approximately $120,000 and are projected to deliver rates of return in excess of 100% based on actual cash flows through year-end, projected incremental production and futures prices reflected on forward markets on December 31, 2003. At the end of 2003, we had 136 proven D-J Basin refrac projects reflected in our reserve report. During the fourth quarter of 2003, we conducted two well operations to fracture-stimulate the Codell formation for a third time, referred to as a tri-frac. Based on encouraging short-term performance results, we believe that tri-frac operations may provide future opportunities to add reserves and production on many of our existing D-J Basin wells, but none of these are included in estimated proved reserves at the end of 2003.

We plan to continue our development and exploitation activities in the D-J Basin, and are currently budgeting for capital investments in the area aggregating approximately $14 million in 2004. Planned activities include drilling approximately 35 new Codell/Niobrara wells and refracing, tri-fracing or recompleting approximately 50 wells in the Codell and/or the Niobrara formation. Our plans are subject to revision, however, based on economic conditions, performance results, activities conducted in other areas, and other factors. New wells, refracs and recompletion operations in the D-J Basin are characterized by flush production at relatively high rates for a few months, after which relatively shallow decline rates are established at lower production levels. Therefore, we may accelerate these operations when oil and gas prices are high or defer them when prices are low, to enhance the impact on investment returns from the flush production.

Powder River Basin Coalbed Methane

At December 31, 2003, we controlled leaseholds covering approximately 110,000 gross (97,000 net) acres in the Powder River Basin CBM play and had established proved gas reserves totaling approximately 34,965,000 Mcf on a small portion of this acreage. These CBM reserves represented 28% of Prima s total estimated proved oil and gas reserve quantities at the end of 2003. Our net gas production from this area increased from an average of approximately 4,300 Mcf per day in 2002 to 17,700 Mcf per day in 2003, due to performance of our Porcupine-Tuit property where wells placed on-line in 2002 produced for a full year and additional wells were drilled and brought on-line. In 2003, the Powder River Basin CBM area accounted for 42% of our total oil and gas production and 32% of our oil and gas sales revenues (excluding hedging effects). Based on current market conditions and excluding the potential impact of exploratory discoveries or proved property acquisitions, we expect that our future activities in the Powder River Basin CBM area will account for significant portions of our capital expenditures, proved reserve additions and new sources of production during the next several years. There is no certainty, however, that future activities will generate the results that we currently project.

As of December 31, 2003, we had drilled 418 wells and acquired five wells in the Powder River Basin CBM play. At that date, 105 of these were connected to sales lines (including 99 that were producing gas), 153 were waiting on connection to gathering systems (of which 16 were already on pump, in the process of being de-watered), and the remaining wells were sold (most in 2002). We anticipate that approximately 130 of the 153 wells awaiting connection to gathering systems will be connected during the second half of 2004 and will begin gas production after sufficient de-watering has occurred. The remaining wells awaiting hook-up will be connected to a gathering system once wider-scale development occurs in the areas where these wells are located. Based on engineering estimates prepared as of the end of 2003, our reserve report for this CBM area included 254 proved undeveloped locations and identified over 2,350 additional non-proved prospective drill sites on our leaseholds, subject to economic viability that will be dependent upon projected regional gas prices, estimated development and operating costs, future drilling results from activities by Prima and other operators, and other factors. Prima is majority (often 100%) owner and operator of all of the Powder River Basin CBM properties where it owns a working interest.

The CBM play in the Powder River Basin is prospective over a vast geographic area encompassing approximately three million acres in northeastern Wyoming and southeastern Montana. Industry drilling activity to date has primarily been focused in Wyoming, where most of the acreage and thicker coal seams lie. According to the Wyoming Oil & Gas Commission, over 16,000 Powder River Basin CBM wells have been drilled in the state through the end of 2003 and

Table of Contents

approximately 12,000 of these wells were producing an aggregate of approximately 950 MMcf of natural gas per day during December 2003. At times during the past five years, this has been the most active drilling play in the United States. Although activity levels moderated in 2002 and 2003, due to unsettled federal land use issues (discussed below), depressed regional gas prices in 2002, and other factors, significant estimated potential gas reserves remain unexploited in the area.

The primary target coals are found in the Fort Union formation at depths ranging from 600 feet to 2,200 feet. It is common to encounter multiple coal zones varying in thickness from a few feet to over 150 feet between these depths. The methane in coal beds is adsorbed, or attached, within the coal layers and is held in place by water within the coals. When water is produced from the coal seam, the pressure is reduced, allowing the gas to desorb from the coal. Operators in the area have experienced de-watering times ranging from a few days to over one year, with the de-watering time influenced by well density, coal depth, permeability, gas content, structure and other factors. Gas production rates from individual wells in the play have ranged from a few Mcf per day to over 1,000 Mcf per day after sufficient de-watering.

Significant industry CBM drilling activities in this area began in 1994 and have primarily been focused on developing reserves in the Wyodak coal, on the east side of the basin. Typically, costs for these wells (including allocable costs for related surface equipment and infrastructure) averaged $70,000 to $90,000 per well, and yielded gross gas reserves averaging 250,000 to 300,000 Mcf per well. Future drilling operations are expected to be focused on development of the Big George, Wall and other coal seams that are generally deeper and often thicker than the Wyodak coal. We expect that as these deeper, thicker coals are developed, the gas reserves and production per well and the average drilling, completion and operating costs per well will be greater than experienced so far to develop the Wyodak coal seam.

To produce gas in this CBM play, wells generally must be hooked-up to a low-pressure gathering system and compression, commonly referred to as screw compression, which typically holds wellhead pressure to less than 10 pounds per square inch gauged (psig). The gas must then move through a gathering system where, at its terminus, gas needs to be further boosted to about 1,400 psig to enter a high-pressure header-system line. This high-pressure boost is commonly referred to as reciprocating (or recip) compression. CBM gas from this area is generally somewhat less than 1,000 Btu per Mcf and may require carbon dioxide extraction to meet interstate pipeline gas quality specifications. Due to relatively high compression and transportation costs, net price realizations for this gas are below Rocky Mountain indices. The amount of the discount varies with the nominal level of the indices, Btu content of the gas, location of the property, fuel use and other factors, but in 2003 Prima s realized price on production from CBM wells averaged $2.87 per Mcf, compared to the CIG index average of $4.04, for a difference of $1.17 per Mcf.

Our CBM-prospective net acreage holdings in the Powder River Basin at the end of 2003 were comprised of approximately 83% federal, 7% state, and 10% fee (private) leases. Generally, the federal leases have an initial ten-year term, state leases have a five-year term, and the terms of fee leases vary from a few months to several years. The primary lease terms of federal acreage have generally been extended for the period that access to the lands has been restricted while an Environmental Impact Statement (EIS) was pending or subject to legal challenge after its completion.

On April 30, 2003, the BLM issued the final Record of Decision (ROD) in relation to its EIS regarding future CBM drilling in the Powder River Basin. Among other conditions for future operations, this ROD requires additional surveys for plant and animal species and cultural artifacts, and noxious weed mitigation. We have filed permit applications for approval by the BLM under the terms of the new EIS, but cannot predict whether or when such permits will be granted. Since the issuance of the final ROD, the BLM has been reviewing their permitting processes in an effort to eventually facilitate issuance to industry of approximately 3,000 drilling permits per year for this area, but actual issuances of permits have so far continued to be made at a fraction of that pace. BLM permit issuances may also be affected for some period by several pending lawsuits that were filed shortly after the ROD was issued, challenging portions of the BLM s decision. At this time, we are unable to predict the outcome of this matter or its impact on our planned operations in the Powder River Basin. A significant portion of the wells we plan to drill in 2004 would require federal permits to be issued by the BLM. However, we do not expect that any limitations on our ability to drill during 2004 will affect the rate of our production until late in the year.

The Wyoming Department of Environmental Quality (DEQ) is responsible for considering applications for water discharge permits and air discharge permits, which are required to operate natural gas fired compressors. Water produced from CBM wells is generally potable (drinking water quality) and permits to discharge water on the surface had generally been attainable early in development of the eastern side of the basin. However, issuance of permits to surface discharge water was significantly slowed during the past two years in order to allow further study of the potential impacts of the mineral content of the water on agriculture and wildlife. It is expected that, in the future, the Wyoming DEQ will generally require water management techniques other than surface discharge, such as collection in containment reservoirs or treating, in accordance with conditions also outlined in the BLM s EIS. These additional requirements will add to the costs of CBM development and production, but we do not believe that they will materially impact the economic viability of the play. We have not encountered, nor do we expect to encounter, significant difficulties in obtaining air permits for our CBM operations from the DEQ.

The transportation infrastructure in this basin is currently capable of moving approximately 1,500,000 Mcf per day of natural gas, compared to the estimated 950,000 Mcf per day produced in December 2003. Downstream of these header systems serving the Powder River Basin, the pipeline grid has been significantly enhanced over the past year by several interstate pipeline expansions, creating adequate capacity at present to transport gas from the Rocky Mountain region to other markets. We do not currently own firm transportation for our own account, and so are relying on availability of capacity on pipelines in order to market our gas.

We established our first significant Powder River Basin CBM production in 2001 from the Stones Throw property (in the northern part of the play), where gross production rates increased over several months to a level in excess of 8,000 Mcf per day (approximately 6,800 Mcf net) shortly before the time the property was sold in March 2002. In July 2002, we initiated production from 27 wells at our Porcupine-Tuit CBM property (in the southern part of the play). Production from this property increased over the balance of the year and in 2003, as wells de-watered, more wells were drilled and hooked up, and additional third-party-owned compression capacity was installed. At the end of 2003, 85 wells had been drilled and hooked up at Porcupine-Tuit and were producing at a combined gross rate of approximately 25,000 Mcf per day (approximately 19,500 Mcf net). Overall, predominantly reflecting contributions these two properties, Prima s Powder River Basin CBM properties accounted for net production averaging approximately 4,000 Mcf per day, 4,300 Mcf per day, and 17,700 Mcf per day, respectively, in 2001, 2002, and 2003. These early-stage developments primarily targeted relatively shallow Wyodak coals.

During 2003, Prima drilled 76 gross (57.7 net) Powder River Basin CBM wells and our direct capital expenditures on the Powder River Basin CBM play, including surface equipment and related infrastructure, totaled approximately $8.5 million. Activities during the year were focused on Porcupine-Tuit, where we drilled 24 wells, and on project areas in the central part of the basin where most of our core undeveloped land holdings in the play are concentrated. These include our Kingsbury, Cedar Draw and North Shell Draw project areas, located approximately 15 to 25 miles west and northwest of Gillette, Wyoming, where 2003 drilling activities were conducted to continue evaluation and development of four main identified coal seams, from the shallower Lower Anderson coal to the deeper Wall coal, found at depths ranging from 700 feet to 2,000 feet. These areas account for most of the previously-drilled wells that we intend to tie in to a gathering system in 2004. Further west lie additional key project areas where we control significant acreage, including Wild Turkey, where the Big George coal is found at approximately 1,300 feet, and Fortification Creek, which also has multiple developable coal seams at depths ranging from 700 feet to 1,600 feet. We anticipate that it will take some time to establish significant proved CBM reserves and production from these areas, particularly from the deeper coals, as they are untested in much of the basin and extensive de-watering will likely need to occur before commercial quantities of gas production can be realized. Furthermore, it is not assured that these projects will ultimately be successful and that they will yield significant reserves and production.

We are currently budgeting for capital investments in the Powder River Basin CBM play during 2004 of approximately $24 million for drilling costs, production equipment, and related infrastructure costs. Planned activities are focused primarily in the Kingsbury, Cedar Draw, North Shell Draw and Wild Turkey project areas. Our preliminary plans call for drilling an estimated 150 wells and hooking up most of these and 130 previously-drilled wells into gathering systems, as well as investing in infrastructure such as power connections and water management facilities. Due to uncertainties regarding regulatory approvals needed to conduct these activities, we can make no assurance that we will be able to conduct the operations that we have planned or that we will reach the targeted level of capital investments.

Other

Powder River Basin, Conventional. At the end of 2003, Prima owned working interests in 17 gross (12.8 net) conventional wells in the Powder River Basin, and deep-rights (below the coals) under 2,000 gross (1,400 net) developed acres and 160,000 gross (146,500 net) undeveloped acres in the area. Our estimated proved reserves at the end of 2003 from conventional sands in the Powder River Basin totaled 2,602,000 Mcf of natural gas and 60,000 barrels of oil, or 2,964,000 Mcfe, representing 2.4% of our total estimated proved reserve quantities. During 2003, Prima s net production from these properties averaged approximately 1,400 Mcfe per day, accounting for 3.3% of our total oil and gas production and 3.4% of our oil and gas sales revenues (excluding hedging effects). Our net production from Powder River Basin conventional wells was 24% lower in 2003 than in 2002, reflecting natural depletion, as no new wells were drilled. No significant activity is currently planned for 2004.

Cave Gulch (Wind River Basin). At the end of 2003, Prima owned primarily non-operated working interests in 50 gross (3.8 net) wells in the Cave Gulch Field in the Wind River Basin. Our Wind River Basin acreage position is comprised of 1,240 gross (170 net) developed acres and 37,000 gross (23,000 net) undeveloped acres. Prima s estimated proved reserves at the end of 2003 attributable to this area totaled 4,644,000 Mcf of natural gas and 14,000 barrels of oil, or 4,727,000 Mcfe, representing 3.8% of our total estimated proved reserve quantities. During 2003, Prima s net production from the Cave Gulch Field averaged approximately 2,000 Mcfe per day, accounting for 4.7% of our total oil and gas production and 5.3% of our oil and gas sales revenues (excluding hedging effects). Our net production from Cave Gulch wells was 20% higher in 2003 than in 2002, as new wells and recompletions offset natural depletion. Prima s capital investments at Cave Gulch in 2003 aggregated approximately $2.3 million, including costs of participating in drilling 17 gross (1.3 net) wells. The operator has indicated that up to six gross (0.5 net) additional wells are preliminarily planned for 2004, for a projected net Prima investment of approximately $1 million.

Coyote Flats Prospect. Prima s Coyote Flats Prospect is located 15 to 25 miles northwest of Price, Utah, and is approximately 15 miles northwest of the Drunkard s Wash Field, which is expected to ultimately produce in excess of 1.2 Tcf of natural gas from the Cretaceous Ferron coals and sandstones. We control approximately 75,000 gross (73,000 net) undeveloped acres within the prospect area. Data from drilling operations conducted on the Coyote Flats acreage during the 1950 s indicated gas shows from the Emery coal seam interval, the Ferron sand and the Dakota sand. Our primary exploratory objectives at Coyote Flats are coal beds in the Emery member of the Mancos shale and the Ferron sandstone interval. Emery coals are found across the majority of the lease position at depths below 3,000 feet, while the Ferron sandstone is found on the acreage at depths ranging from 5,000 to 8,500 feet.

During the fourth quarter of 2002, we drilled a 100%-owned exploratory well on the Coyote Flats Prospect, to begin to evaluate the Emery coals and the Ferron sandstone. The Scofield-Thorpe #22-41 well was drilled and cased to a total depth of 6,247 feet, before operations were suspended for the winter. The well encountered an aggregate 122 feet of Emery coal, from numerous coal beds, including eight with a thickness exceeding five feet, and the Ferron sandstone section was drilled between 5,991 and 6,247 feet. Encouraging gas shows were encountered while drilling from several of the Emery coal beds and from fractured shales and sandstones in the Ferron section.

In the second half of 2003, Prima initiated completion and testing of the Ferron sandstone reservoirs in the Scofield-Thorpe #22-41 well. We completed a 30-day production test on the well followed by a 7-day pressure build-up test. The test results were encouraging, as gas rates of 1,100 Mcf per day and water rates of 150 bpd were measured, with gradually increasing gas rates and decreasing water rates. During 2004, we plan to conduct follow-up drilling on the Coyote Flats Prospect to further evaluate the Ferron sandstone reservoirs, and we also expect to initiate a multi-well pilot program to test the Emery CBM potential. We may seek a partner to participate in these operations.

East Clear Creek Prospect. We control approximately 9,000 gross and net acres in our East Clear Creek Prospect, located approximately 15 miles west of Price, Utah. This prospect is one mile east of Clear Creek Field, and two miles west of the Gordon Creek Field, both of which have produced from the Cretaceous Ferron sandstone. The Clear Creek Field produced in excess of 135 Bcf from 16 wells and the Gordon Creek Field was recently producing at a gross rate of approximately 2,700 Mcf per day from five wells placed on line over the past year. Prima has been working with the U.S. Forest Service and the Bureau of Land Management on an EIS that must be completed before drilling permits will be issued on this prospect. We expect to receive a permit to drill a test well on this prospect later this year and plan to drill a well as soon as practicable thereafter that will target the Ferron and Dakota sandstones at a depth of approximately 7,000 feet on a seismically-defined structure.

Flat Canyon Prospect. Prima owns approximately 6,600 gross and net acres under its Flat Canyon Prospect, located in Emery County, Utah. Our acreage immediately offsets the Flat Canyon Field, which was discovered in 1952. The Flat Canyon Field has produced 9.6 Bcf of natural gas and 14,000 barrels of oil from six wells completed in the Cretaceous Ferron sandstones. We plan to test the Cretaceous Ferron and Dakota formations on the prospect at depths between 6,500 and 7,500 feet. Prima is currently working with the U.S. Forest Service and the Bureau of Land Management to permit a well on this prospect.

Christmas Meadows Prospect. Prima currently holds leases or farmout rights representing approximately a 47% working interest in the Table Top Federal Unit, which is comprised of approximately 24,000 gross acres in Summit County, Utah, roughly 30 miles south of Evanston, Wyoming. The Christmas Meadows prospect, within the Unit, is a large seismically-defined anticlinal closure along the Uinta Mountain front, within the Rocky Mountain Overthrust Belt. Several potential pay sands have been identified down to an estimated depth of approximately 18,000 feet. This project has been delayed for several years and the federal leases have been temporarily suspended while the U.S. Forest Service was preparing an EIS and considering a revision of the forest plan for the area. It currently appears that these issues may be near resolution, enabling a test well to be spudded in the second half of 2004 or in 2005. The initial test well is expected to be drilled to a depth of approximately 15,000 feet to test the Frontier and Dakota sandstones. Once operations in the unit are commenced, Prima and its partners will have approximately six months to establish capability of commercial production, otherwise certain leases will expire. We anticipate participating in the test well for all or a portion of our current working interest.

Merna Prospect. Prima owns an average 35% working interest in 74,000 gross acres in the greater Merna area, located in the northern Green River Basin, in Sublette County, Wyoming. The Merna anticlinal structure is 20 miles northwest of the prolific Pinedale Anticline, where the over-pressured Cretaceous Lance and Mesaverde formations are under extensive development. The same objectives are targeted on the Merna Prospect. In late 2002, the Miller Federal #7-4 well was drilled by another operator along the Merna anticline on lands in which Prima had farmed out its 50% working interest. An affiliate of this operator installed a 36-mile natural gas pipeline to facilitate extended production testing and market sales for this well and future wells that might be drilled in the Merna area. The Miller Federal #7-4 well exhibited strong gas shows at high pressure while drilling but subsequent completion of the well in 2003 resulted in only modest production rates. This well and previous drilling in the area have established the presence of a thick Lance sand interval with gas in place, but project success will likely depend on encountering naturally-fractured reservoirs or successful application of fracture stimulation, due to relatively low porosity and permeability. In 2002, a large regional 3-D seismic survey that encompassed a large portion of the Merna Prospect acreage was completed. In late 2003, another operator initiated a test well on Merna acreage in which Prima held an interest. Prima is participating in the Sage Flat Federal #17-20 well, with a 6.3% working interest before payout and a 10.9% working interest after payout. The Sage Flat Federal #17-20 well is located three miles north of the Miller Federal #7-4 well.

Table of Contents

Proved Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Net proved reserves as of December 31, 2003, 2002 and 2001 were estimated by Prima s engineers and audited by Netherland, Sewell and Associates, Inc., independent petroleum engineers.

The table below sets forth the estimated quantities of net proved reserves attributed to our property interests at the end of each of the last three years, and the present value of estimated future net cash flows attributed to such reserves using prices in effect as of the respective year-end dates, held constant. The average net realizable prices used to estimate proved reserve quantities at the end of 2003, 2002, and 2001, respectively, were as follows: $4.95, $2.64, and $1.94 per Mcf for natural gas; and $32.88, $31.30, and $19.71 per barrel of oil. In accordance with Securities and Exchange Commission guidelines, projected future net cash flows from production of proved reserves were discounted by ten percent per annum to derive present values and the Standardized Measure of discounted future net cash flows after income taxes. The 10% discount factor is not necessarily a market rate, and present value, no matter what discount factor used, is materially affected by assumptions as to future prices and costs and timing of future production, which may prove to be inaccurate. For further information concerning estimated proved reserves and the discounted future net cash flows related to these reserves, see unaudited Supplementary Oil and Gas Information in Note 12 within the Notes to Consolidated Financial Statements.

	2003	2002	2001
Estimated proved natural gas reserves (Mcf)	96,000,000	87,440,000	115,222,000
Estimated proved oil reserves (barrels)	4,966,000	3,944,000	3,394,000
Present value of estimated future net cash flows, before future income tax expense	$239,800,000	$128,843,000	$ 91,905,000
Standardized measure of discounted future net cash flows	$158,979,000	$ 91,279,000	$ 66,801,000

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing and amounts of development expenditures. Oil and gas reserve engineering should be recognized as a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available engineering and geological data and interpretation, and judgment. Results of drilling, testing and production after estimates are prepared may justify revisions. Accordingly, reserve estimates are often materially different from the quantities of oil and natural gas that are ultimately produced. We are not currently aware of any developments subsequent to December 31, 2003 that we believe would warrant a significant upward or downward revision to our estimated proved reserves as of that date. Oil and natural gas prices have historically been volatile and are expected to continue to be so in the future. Changes in product prices affect the economic limits and, therefore, recoverable reserve quantities of oil and gas wells, as well as the present value of estimated future net cash flows and the standardized measure of discounted future net cash flows.

Since January 1, 2003, we have filed Department of Energy Form EIA-23, Annual Survey of Oil and Gas Reserves, as required of operators of domestic oil and gas properties. There are differences between the reserves as reported on Form EIA-23 and reserves as reported herein. Form EIA-23 requires that operators report on total proved developed reserves for operated wells only and that the reserves be reported on a gross operated basis rather than on a net interest basis.

Table of Contents

Production

The following table summarizes information with respect to our producing oil and gas properties for each of the periods shown.

	2003	2002	2001
Quantities sold:			
Natural gas (Mcf)	13,015,000	8,343,000	9,277,000
Oil (barrels)	401,000	373,000	431,000
Total natural gas equivalents (Mcfe)(1)	15,421,000	10,580,000	11,863,000
Average sales price (including hedging effects):			
Natural gas (per Mcf)	$ 3.53	$ 1.97	$ 3.60
Oil (per barrel)	$ 31.71	$ 25.14	$ 25.88
Total natural gas equivalents (per Mcfe)(1)	$ 3.80	$ 2.44	$ 3.76
Average production costs, including production taxes, per Mcfe (1)	$ 0.61	$ 0.49	$ 0.56

(1) Oil production has been converted to a common unit of production (Mcfe of natural gas) on the basis of relative energy content (one barrel of oil to six Mcf of natural gas).

Productive Wells

The following table summarizes our total gross and net productive wells as of December 31, 2003.

	Productive Wells			
	Oil		Gas	
	Gross (1)	Net (2)	Gross (1)(3)	Net (2)(3)
Operated:				
Colorado	21	20.0	415	383.6
Wyoming			272	232.5
Non-operated:				
Colorado			19	8.1
Utah			1	0.4
Wyoming			53	4.7
Total (4)	21	20.0	760	629.3

Additionally, we own royalty interests in 148 gross wells that are not included in the above table.

(1) A gross well is a well in which a working interest is held. The number of gross wells is the total number of wells in which a working interest is owned.

(2) A net well is deemed to exist when the sum of fractional ownership interests in gross wells equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

(3) Includes 153 gross (124.1 net) CBM wells in Wyoming that were awaiting hook-up at year-end.

(4) Wells are classified as oil wells or gas wells according to predominate production stream. Multiple completions (28 wells) are counted as one well.

Table of Contents

Developed and Undeveloped Acreage

At December 31, 2003, our oil and gas lease holdings were as follows:

	Developed Acreage (1)		Undeveloped Acreage (2)	
Location	**Gross (3)**	**Net (4)**	**Gross (3)**	**Net (4)**
Denver-Julesburg Basin	19,110	16,570	12,000	11,000
Green River Basin	320	40	86,000	36,000
Powder River Basin	14,870	12,900	177,000	158,000
Uinta Basin	160	160	105,000	102,000
Wind River Basin	1,240	170	37,000	23,000
Other basins	1,500	60	56,000	30,000
Total	37,200	29,900	473,000	360,000

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. We have generally been able to obtain extensions of the primary terms of our federal leases for the period that we have been unable to obtain drilling permits due to a pending EIS or related legal challenges. The following table sets forth the expiration periods of the gross and net acres subject to leases summarized in the table of undeveloped acreage, unless such leases are currently held by production from a portion of the lease that has been developed.

	Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2004	51,000	25,000

December 31, 2005	82,000	56,000
December 31, 2006	34,000	34,000
December 31, 2007	25,000	22,000
December 31, 2008	80,000	73,000
December 31, 2009 and later	126,000	117,000
	398,000	327,000

Table of Contents

Drilling Activities

Certain information with regard to our drilling activities for the years ended December 31, 2003, 2002 and 2001 is set forth below:

	2003		2002		2001	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	67	51.1	55	50.1	123	121.3
Dry						
	67	51.1	55	50.1	123	121.3
Exploratory:						
Productive	52	34.7	18	11.0	14	14.0
Dry					2	0.3
	52	34.7	18	11.0	16	14.3
Total:						
Productive	119	85.8	73	61.1	137	135.3
Dry					2	0.3
	119	85.8	73	61.1	139	135.6

Present Activities

Year-to-date through February 27, 2004, we had drilled nine gross and net wells in the D-J Basin. Six of these wells were producing at that date, one was waiting on tie-in to a sales line and two were waiting on completion. We also restimulated (refraced or tri-fraced) 14 gross (12.8 net) wells in the D-J Basin, all of which have been restored to production. During this same period, we drilled five gross and net wells in the Powder River Basin CBM play and participated in drilling two non-operated (0.1 net) wells in the Cave Gulch area, all of which were waiting on completion as of February 27, 2004.

Natural Gas and Oil Marketing, Trading and Price Risk Management

Prima s marketing and trading activities may include marketing our own production, marketing the production of other owners in wells that we operate, and the purchase and resale of third-party owned production. This oil and gas production is principally sold to end users, marketers, refiners and other purchasers having access to pipeline facilities or the ability to truck oil to local refineries. The marketing of oil and gas can be affected by a number of factors that are beyond our control and which cannot be accurately predicted. At times, we use financial instruments to hedge the price of a portion of our production or production of others that we have committed to purchase for resale.

In 2003, revenues from the sale of Prima s natural gas production, including related hedging effects, totaled $45,911,000, representing 78% of our and gas sales and 65% of our consolidated total revenues. Revenues from the sale of Prima s crude oil in 2003, including hedging effects, totaled $12,711,000, representing 22% of our oil and gas sales and 18% of our consolidated total revenues.

Natural Gas

The terms and conditions of our natural gas sales contracts vary as to price, quantity, term and other conditions, but in general follow 30-day index or day-to-day spot market prices. We occasionally sell gas at a fixed price for periods greater than 30 days as an effective price hedge, but had no such fixed-price sales arrangements in effect at year-end 2003. We currently have two significant purchasers for our natural gas, Duke Energy Field Services, LLC (Duke) and Western Gas Resources, Inc (Western). Neither of these companies is affiliated with Prima and, while loss of either as a purchaser or customer might have a material adverse effect on our business, we believe that we could arrange to sell our gas to alternate customers on reasonably comparable terms.

Natural gas produced in the D-J Basin is high in heating content and must be processed to extract natural gas liquids. Duke purchases most of our D-J Basin gas at the wellhead, under contracts that provide for Prima to receive fixed percentages of the proceeds generated by Duke s sale of residue gas and natural gas liquids after the gas is processed at Duke s plants. Net sales to Duke in 2003 accounted for approximately $19,193,000, or 27% of our total consolidated revenues.

Western purchases much of our gas production in the Powder River Basin, including CBM gas from wells in the Porcupine-Tuit area. This CBM gas, which accounted for over 95% of our sales to Western in 2003, is sold at the inlet to Western s compression facilities at prices based on the monthly CIG index less certain costs for compression and transportation. Net sales to Western in 2003 accounted for approximately $19,062,000, or 27%, of our total consolidated revenues.

Our current gas gathering and marketing agreements generally arrange to get our gas from the wellhead into high-pressure header systems or interstate pipelines. We have not, however, contracted for downstream transportation on a firm basis. As such, we have no liability to pay reservation (demand) charges for header or pipeline capacity, but we also have no assurance that our gas will flow every day and we are at risk that regional imbalances between gas supply and pipeline capacity will unfavorably impact the gas prices that we realize for our production. No significant curtailments of gas production occurred during the three-year period ended December 31, 2003, but limited pipeline capacity did create conditions during several months, particularly between mid-2002 and mid-2003, in which the netback price that we received for our natural gas was significantly below prices being paid for gas elsewhere in the country. Due to expansions of pipeline capacity during 2003, we do not expect such conditions to recur in the near-term.

At times, we have also engaged in purchasing and re-selling third-party gas within our areas of operations. These arrangements typically provide for the purchase of natural gas at a known price or index, with a corresponding sale at a net margin. However, from time to time we may have open purchase or sale commitments without corresponding re-sale contracts, which could result in losses. Prima s Chief Executive Officer reviews such opportunities before commitments are made and we closely monitor the mark-to-market gains or losses of such positions. We had no purchase-for-resale trading obligations outstanding at the end of 2003 and had entered into no commitments after year-end 2003 through February 27, 2004.

Oil

Our oil production is typically sold to refiners, marketers and other purchasers that truck it to local refineries or pipelines. The price is generally based on a prevailing spot market index, such as NYMEX, with adjustments for quality and location. We currently have one significant purchaser of crude oil, Valero Energy Corporation, which accounted for approximately $11,831,000, or 17%, of our total consolidated revenues in 2003. We are not affiliated with Valero and believe that we could sell our crude oil to other purchasers should we lose Valero as a purchaser, though the terms might be less favorable.

Price Risk Management

We sometimes utilize commodity futures, over-the-counter swaps or similar derivatives to mitigate risks related to the volatility of oil and gas prices. Such transactions can also be used to protect against the risk of an expanding differential between NYMEX and Rocky Mountain gas prices, which can occur when Rocky Mountain gas supplies exceed regional demand and pipeline capacity out of the Rocky Mountain region or due to other factors, such as regional weather differences. A portion of these contracts did not meet all of the conditions required for utilization of hedge accounting, but were nevertheless viewed by us as providing considerable revenue protection in the event of declining oil or gas prices. See Item 7A, Quantitative and Qualitative Disclosures about Market Risk, below for additional disclosures relating to derivatives, including our open derivative positions as of February 27, 2004.

Title to Oil and Gas Properties

As is customary in the oil and gas industry, we typically conduct only a preliminary title examination at the time that we acquire leases of properties believed to be suitable for drilling operations. Prior to the commencement of drilling

Table of Contents

operations, however, we engage independent attorneys to conduct a thorough title examination of drill site tracts. Once production from a given well is established, a division order title report is prepared, which indicates the proper parties and percentages for payment of production proceeds, including royalties. We believe that titles to Prima s leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Oilfield Services

We conduct our oilfield services business under the names of Action Oilfield Services in Colorado and Action Energy Services in Wyoming.

Action Oilfield Services

Action Oilfield Services (AOS) has been active in the D-J Basin since 1986, operating out of a field office and yard near LaSalle, Colorado. AOS owns various well servicing equipment including eight completion rigs, a swab rig, tractor trailer rigs for water hauling, and oilfield rental equipment, such as pumps, tanks and blowout preventers. During 2003, we experienced high utilization rates for our people and equipment due to strong demand for services for well recompletions, re-works and drilling in the area. We intend to continue with our well servicing activities in the D-J Basin and will seek opportunities to profitably expand the business. AOS provides services for Prima as well as third-party operators in the area. During 2003, 22% of AOS s revenues were from activities performed for Prima. AOS fees and costs associated with pt date. Shares that are issued to officers on the exercise dates of their stock options may be issued net of the statutory withholding requirements to be paid by us on behalf of our employees. As a result, the actual number of shares issued will be fewer than the actual number of shares exercised under the stock option. We recognize stock-based compensation using the straight-line method.

For the three months ended September 30, 2013 and 2012, we recognized stock-based compensation of approximately $60 thousand and $200 thousand, respectively. For the nine months ended September 30, 2013 and 2012, we recognized stock-based compensation of approximately $270 thousand and $830 thousand, respectively. Related income tax benefits were not recognized, as we incurred a tax loss for both years.

Fair Value of Financial Instruments

The carrying amounts of our financial instruments, including cash and cash equivalents, accounts receivable, accounts payable, and accrued liabilities, approximate fair value because of their generally short maturities. We carry marketable securities at fair value.

Cash and Cash Equivalents, Restricted Cash and Marketable Securities

We invest our excess cash in money market mutual funds, and mutual bond funds. We classify all highly liquid investments with stated maturities of three months or less from date of purchase as cash equivalents and all highly liquid investments with stated maturities of greater than three months as marketable securities. We hold cash balances in excess of the federally insured limits of $250,000 with two prominent financial institutions. We deem this credit risk not to be significant as our cash is held by major prominent financial institutions. Total cash and cash equivalents held in checking accounts and a money market core cash account, as reported on the accompanying consolidated balance sheets, totaled approximately $0.4 million and $2.2 million at September 30, 2013 and December 31, 2012, respectively.

Restricted cash represents cash being held by one prominent financial institution that is being used as collateral for our corporate credit cards and our letters of credit issued to some of our customers. There was approximately $24,000 of outstanding letters of credit as of September 30, 2013. The total balance of our restricted cash at September 30, 2013 and December 31, 2012, was approximately $0.6 million.

We determine the appropriate classification of our investments in marketable securities at the time of purchase and reevaluate such designation at each balance sheet date. We have classified and accounted for our marketable securities as available-for-sale, however we carry these securities at fair value (see below election made to value these financial instruments at fair market value). The fair value of all securities is determined by quoted market prices.

All marketable securities are classified as available-for-sale securities and are reported at their fair value (level 1). A level 1 measurement under the FASB pronouncements is the first tier of a three tier hierarchy for fair value measurements used in valuation methodologies. This valuation level allows for fair value measurements where the inputs are the quoted prices for the assets in the active markets. All of our marketable securities have quoted market prices and these quoted prices are used to determine the cost basis and fair value of our marketable securities.

The total quoted fair value of our marketable securities at September 30, 2013 and December 31, 2012 was approximately $0.0 million and $1.6 million, respectively. This amount was held in the following mutual funds at December 31, 2012: (1) Doubleline Total Return Bond Fund (Symbol - DLTNX) -$0.8 million; (2) Vanguard High Yield Corp Investor Fund (Symbol -VWEHX) - $0.1 million; and (3) Vanguard GNMA Investor Fund (Symbol -VFIIX) - $0.7 million at December 31, 2012. The cost basis of these above investments was approximately $1.1 million.

The amount recorded as unrealized gain (loss), realized capital gain or loss, interest and dividends received, as reported to us from the financial institutions in which they were reinvested, and that we reported under the caption of investment income (loss) in the accompanying consolidated statement of operations, totaled approximately $2,000 and $153,000 for each of the three month periods ended September 30, 2013 and 2012, respectively and $(9,000) and $387,000 for each of the nine months ended September 30, 2013 and September 30, 2012, respectively. We elected the fair value option permitted under FASB ASC 825 to report the unrealized gains and losses from our marketable securities in our accompanying consolidated statement of operations instead of other comprehensive income and loss. Management believes the fair value option provides a better indication of the Company s performance.

Income Taxes

Income taxes are accounted for under the asset and liability method in accordance with United States generally accepted accounting principles. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial carrying amounts of existing assets and liabilities and their respective tax bases as well as operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance to the extent that the recoverability of the asset is unlikely to be recognized. We did not provide any current or deferred income tax provision or benefit for any periods presented to date because we have continued to experience a net operating loss since inception and therefore provide a 100% valuation allowance against all of our deferred tax assets (see Note 5-Income Taxes).

The Company adopted the FASB ASC accounting guidance for recognizing and measuring uncertain tax positions, as defined in the FASB ASC Topic *"Income Taxes* . This guidance prescribes a threshold condition that a tax position must meet for any of the benefits of the uncertain tax position to be recognized in the financial statements. This guidance also provides accounting guidance on derecognizing, classification and disclosure of these uncertain tax positions. The Company recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in operating expenses. The Company has not recognized any interest and penalties in 2013 or 2012.

Research, Development and Related Expenses

These costs from our Technology business segment are charged to operations in the year incurred and are shown on a separate line on the accompanying Consolidated Statement of Operations.

Segment Reporting

We use the management approach in determining reportable operating segments. The management approach considers the internal organization and reporting used by our chief decision makers for making operating decisions and assessing performance, as the source for determining our reportable segments. We have determined that we have two operating segments as defined by the FASB accounting pronouncement, *Disclosures about Segments of an Enterprise and Related Information*. As discussed above, our two reporting business segments are our technology business and our consulting services business.

Recent Accounting Pronouncements

The Company does not expect the adoption of any recent accounting pronouncements to have a material impact on its financial statements.

Note 2. Net Loss Per Share

Basic net loss per share is computed using the weighted-average number of common shares outstanding during the reporting period. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the reporting period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, warrants, restricted shares, and unvested common shares subject to repurchase or cancellation. The dilutive effect of outstanding stock options, restricted stock units, and warrants is not reflected in diluted earnings per share because we incurred net losses for the three months and nine months ended September 30, 2013 and 2012, and the effect of including these potential common shares in the diluted earnings per share calculations would be anti-dilutive and are therefore not included in the calculations.

Note 3. Accounts Receivable - Project Revenue and Project Costs

ENEC and FANR Projects

The total accounts receivable from the ENEC and FANR contracts was approximately $0.6 million at September 30, 2013 and December 31, 2012. These amounts due from ENEC and FANR represent approximately all of the total accounts receivable reported at September 30, 2013 and December 31, 2012.

Total unbilled accounts receivable included in the accompanying consolidated balance sheets and reported in accounts receivable of approximately $0.1 million and $0.2 million at September 30, 2013 and December 31, 2012 is for work that was billed to our clients in October 2013 and January 2013, respectively. Foreign currency transaction exchange gains (losses) were not significant for the three and nine months ended September 30, 2013 and 2012, respectively, which is reported in the caption other income and expenses on the accompanying consolidated statement of operations.

Travel costs and other reimbursable costs under these contracts are reported in the accompanying statement of operations as both revenue and cost of consulting services provided, and totaled approximately $0.0 million and $0.2 million for the three month periods ended September 30, 2013 and 2012 and approximately $0.1 million and $0.4 million for the nine months ended September 30, 2013 and September 30, 2012, respectively. The total travel and other reimbursable expenses that have not been reimbursed to us and are included in total accounts receivable reported above from our consulting contracts were not significant.

We expect to continue to provide strategic advisory services to ENEC and FANR and we also expect the variation of revenue we earn from these contracts to continue. Under these agreements, revenue will be recognized on a time and expense basis. We periodically discuss our consulting work with ENEC and FANR, who review the work we perform and our reimbursable travel expenses, and accept our monthly invoicing for services and reimbursable expenses.

Note 4. Accounts Payable and Accrued Liabilities

Accounts payable and accrued expenses (in millions) consisted of the following:

	2013	2012
Trade payables	$ 0.1	$ 0.2
Accrued expenses and other	0.2	0.2
Total	$ 0.3	$ 0.4

10

Note 5. Income Taxes

Our tax provision is determined using an estimate of our annual effective tax rate adjusted for discrete items, if any, that are taken into account in the relevant period. The 2013 and 2012 annual effective tax rate is estimated to be a combined 40% for the U.S. federal and state statutory tax rate. We review tax uncertainties in light of changing facts and circumstances and adjust them accordingly. As of September 30, 2013 and December 31, 2012, there were no tax contingencies recorded.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities recognized for financial reporting, and the amounts recognized for income tax purposes. The significant components of deferred tax assets (at a 40% effective tax rate) as of September 30, 2013 and December 31, 2012, respectively, are as follows:

Deferred Tax Assets (in millions)

	Total **2013**	Total **2012**	**Deferred Tax Asset 2013**	**2012**
Capitalized start-up costs	$ 4.7	$ 5.1	$ 1.9	$ 2.0
Stock-based compensation	21.9	21.7	8.8	8.7
Net operating loss carry-forward	38.2	34.4	15.3	13.8
Less: valuation allowance	(64.8)	(61.2)	(26.0)	(24.5)
	$ -	$ -	$ -	$ -

We have a net operating loss carry-forward for federal and state tax purposes of approximately $38 million at September 30, 2013, that is available to offset future taxable income, which will begin to expire in the year 2022. For financial reporting purposes, no deferred tax asset was recognized because at September 30, 2013 and December 31, 2012, management estimates that it is more likely than not that substantially all of the net operating losses will expire unused. As a result, the amount of the deferred tax assets considered realizable was reduced 100% by a valuation allowance. The change in the valuation allowance was approximately $1.5 million for the nine months ended September 30, 2013 and 2012, respectively. Many of the Company s operating expenses in its 2007 and 2006 tax years were classified under the Internal Revenue Code as capitalized Startup Costs , which did not begin to be deductible for tax purposes until 2008. The Company files a consolidated tax return with its subsidiaries. The Company is no longer subject to U.S. federal, state, or non-U.S. income tax examinations by tax authorities for tax years before 2010. The tax returns from prior years to 2009 are subject to examination for the limited purpose of challenging the net operating losses carried forward from those periods.

Note 6. Commitments and Contingencies

Employment Agreements

We have employment agreements with our executive officers and some consultants, the terms of which expire at various times. Such agreements provide for minimum compensation levels, as well as incentive bonuses that are payable if specified management goals are attained. Under each of the agreements, in the event the officer s employment is terminated (other than voluntarily by the officer or by us for cause, or upon the death of the officer), if all provisions of the employment agreements are met, we are committed to pay certain benefits, including specified monthly severance.

Operating Leases

We entered into an agreement to lease office space under the terms of a sublease with a term of 65 months commencing August 1, 2008. Under the terms of the sublease for our office in Virginia, the lease payments are inclusive of pass-through costs. We are not charged additional amounts for real estate taxes and standard operating expenses. We paid the security deposit related to this sublease agreement in the amount of approximately $120,000 (security deposit balance approximately $40,000 at September 30, 2013). We pay monthly rental fees in the amount of approximately $49,000 in accordance with the sublease agreement plus parking fees. We pay rent for our Moscow office of approximately $12,000 per month. The monthly straight-line rental expense from August 1, 2008 to December 1, 2013, is approximately $45,000 under our Virginia sublease agreement. As a result of the straight-line rent calculation generated by the one free rent period and rent escalation, we have recorded in accrued liabilities a deferred rent credit of approximately $11,000 and $33,000 at September 30, 2013 and December 31, 2012, respectively. Total rent expense was approximately $0.2 million for each of the three months periods ended September 30, 2013 and 2012 and approximately $0.5 million for each of the nine months periods ended September 30, 2013 and 2012.

Estimated annual minimum rental payments (in millions) under our operating leases are as follows:

		Total
Year ending - December 31, 2013	$	0.2
Total minimum lease payments	$	0.2

Note 7. Research and Development Costs

Research and Development Costs

Research and development costs, included in the accompanying consolidated statement of operations amounted to approximately $0.6 million and $0.5 million for the three month periods ended September 30, 2013 and 2012, respectively and $1.8 million and $1.6 million for the nine months ended September 30, 2013 and 2012, respectively.

On August 15, 2013, Lightbridge entered into a Professional Services Agreement with Prof. Jean Ragusa to continue the neutronic modeling work that was completed by Prof. Ragusa under Task Order No. 1 issued under our Master Research Services Agreement with Texas A&M University. The initial statement of work (SOW-1) under the Professional Services Agreement with Prof. Ragusa has a fixed price of $40,000 and is expected to be completed by February 15, 2014. The results of this work will be used to enhance our neutronic modeling capability using industry standard computer codes.

In addition, we have consulting agreements with several consultants working on various projects for us, which total approximately $10,000 per month.

Note 8. Stockholders Equity

At September 30, 2013, there are 500,000,000 shares of authorized common stock. Total common stock outstanding at September 30, 2013 and December 31, 2012, was 12,556,400 and 12,526,240 shares, respectively. At September 30, 2013, there were no shares reserved for future issuance, 1,034,996 stock warrants, 1,630,925 stock options outstanding and 15,136 total unvested shares of restricted stock, all totaling 15,237,457 of total stock and stock equivalents outstanding at September 30, 2013.

Stock-based Compensation Stock Options and Restricted Stock

Stock Plan

We have a stock-based compensation plan to reward for services rendered by officers, directors, employees and consultants. On July 17, 2006, we amended this stock plan. We have reserved 2,500,000 shares of common stock of our unissued share capital for the stock plan. Other limitations are as follows:

(i) No more than an aggregate of 1,250,000 shares can be granted for the purchase of restricted common shares during the term of the stock plan;

(ii) The maximum number of shares of common stock with respect to which options may be granted to any one person during any fiscal year may not exceed 266,667 shares; and

(iii) The maximum number of restricted shares that may be granted to any one person during any fiscal year may not exceed 166,667 common shares.

Total stock options outstanding at September 30, 2013 and December 31, 2012, were 1,630,925 and 1,639,842 of which 1,594,126 and 1,523,536 of these options were vested at September 30, 2013 and December 31, 2012, respectively. Stock option expense was approximately $45 thousand and approximately $145 thousand for the three months ended September 30, 2013 and 2012, respectively. Stock option expense was approximately $190 thousand and approximately $560 thousand for the nine months ended September 30, 2013 and 2012, respectively.

Stock option transactions to the employees, directors, advisory board members and consultants are summarized as follows for the nine months ended September 30, 2013:

	Options Outstanding		Weighted Average Exercise Price		Weighted Average Fair Value
Beginning of the year	1,639,842	$	11.46	$	10.85
Granted	-		-		-
Exercised	-		-		-
Forfeited	(7,250)		6.04		5.51
Expired	(1,667)	$	8.55	$	8.01
End of the period	1,630,925	$	11.49	$	10.88
Options exercisable	1,594,126	$	11.62	$	11.01

Stock option transactions to the employees, directors, advisory board members and consultants are summarized as follows for the year ended December 31, 2012:

	Options Outstanding		Weighted Average Exercise Price		Weighted Average Fair Value
Beginning of the year	1,674,065	$	11.37	$	10.74
Granted	-		-		-
Exercised	-		-		-
Forfeited	(167)	$	6.30	$	5.67
Expired	(34,056)	$	9.42	$	7.48
End of the year	1,639,842	$	11.46	$	10.85
Options exercisable	1,523,536	$	11.82	$	11.22

The above tables include options issued and outstanding as of September 30, 2013 as follows:

i) A total of 229,558 non-qualified 8-10 year options have been issued, and are outstanding, to our consultants at exercise prices of $5.70 to $19.20 per share.

ii) A total of 1,129,498 non-qualified 8-10 year options have been issued, and are outstanding, to our directors, officers and employees at exercise prices of $5.42 to $23.85 per share. From this total, 665,088 options are outstanding to the Chief Executive Officer who is also a director, with remaining contractual lives of 2.2 years to 7.5 years. All other options issued to directors, officers and employees have a remaining contractual life ranging from 2.8 years to 7.5 years.

iii) A total of 271,869 non-qualified 10 year options have been issued, and are outstanding, to our advisory board members at exercise prices of $4.50 to $14.40 per share.

The following table provides certain information with respect to the above-referenced stock options that are outstanding and exercisable at September 30, 2013:

	Stock Options Outstanding				Stock Options Vested			
	Weighted Average Remaining Contractual Life - Years	Number of Awards		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life - Years	Number of Awards		Weighted Average Exercise Price
Exercise Prices								
$4.50 - $8.70	5.53	835,884	$	6.33	5.46	799,085	$	6.36
$9.00 - $12.90	4.20	130,037	$	10.46	4.20	130,037	$	10.46
$13.50 - $18.90	2.56	358,336	$	14.17	2.56	358,336	$	14.17
$19.20 - $23.85	1.90	306,668	$	22.84	1.90	306,668	$	22.84
Total	4.09	1,630,925	$	11.49	4.02	1,594,126	$	11.62

The following table provides certain information with respect to the above-referenced stock options that are outstanding and exercisable at December 31, 2012:

	Stock Options Outstanding				Stock Options Vested			
	Weighted Average Remaining Contractual Life - Years	Number of Awards		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life - Years	Number of Awards		Weighted Average Exercise Price
Exercise Prices								
$4.50 - $8.70	6.27	844,801	$	6.33	6.04	728,495	$	6.27
$9.00 - $12.90	4.94	130,037	$	10.46	4.94	130,037	$	10.46
$13.50-$18.90	3.3	358,336	$	14.17	3.3	358,336	$	14.17
$19.20-$23.85	2.65	306,668	$	22.84	2.65	306,668	$	22.84
Total	4.84	1,639,842	$	11.46	4.62	1,523,536	$	11.82

The aggregate intrinsic value of stock options outstanding at September 30, 2013 and December 31, 2012 was $0. Intrinsic value calculated based on the difference between the exercise price of the underlying awards and the quoted price of our common stock as the reporting date ($1.79 and $1.41 per share as of the close on September 30, 2013 and December 31, 2012, respectively).

Restricted Stock Award Activity

	Number of Units		**Weighted Average Grant Date Fair Value**
Total awards outstanding at December 31, 2012	43,032	$	6.49
Units granted			
Units Exercised/Released	(27,896)	$	7.02
Units Cancelled/Forfeited			

Total awards outstanding at September 30, 2013	15,136	$	5.50
Total units vested			
Total units non-vested	15,136	$	5.50
Total shares outstanding at September 30, 2013	15,136	$	5.50

The following summarizes our restricted stock unit activity:

Scheduled vesting for outstanding restricted stock units at September 30, 2013 is as follows:

	Year Ended December 31,					
	2013	2014	2015	2016	Thereafter	Total
Scheduled vesting restricted stock units	843	14,293	--		--	15,136

As of September 30, 2013 and December 31, 2012, there was approximately $40 thousand and $120 thousand of net unrecognized compensation cost related to unvested restricted stock-based compensation arrangements, respectively. This compensation is recognized on a straight line basis resulting in approximately $40 thousand of the compensation expected to be expensed in the next twelve months, and the total unrecognized has a weighted average recognition period of 0.5 years.

We use the historical volatility of our stock price since January 5, 2006, the date we announced that we were becoming a public company, to estimate the future volatility of our stock. At this time we do not believe that there is a better objective method to predict the future volatility of our stock. We estimate the term of our option awards based on the full term of the award. To date we have had very few exercises of our options, and those exercises have occurred just before the expiration date of the awards. Since the strike price of most of our outstanding awards is greater than the price of our stock, generally awards have expired at the end of the term. We estimate the effect of future forfeitures of our grants based on an analysis of historical forfeitures of unvested grants, as we have no better objective basis for that estimate. The expense that we have recognized related to our grants of options and restricted stock includes the estimate for future pre-vest forfeitures. We will adjust the actual expense recognized as future pre-vest forfeitures as they occur. We have estimated that 1.4% and 2.9% of our option and restricted stock grants respectively, will be forfeited prior to vesting.

There were no stock options granted for the nine months ended September 30, 2013 and the year ended December 31, 2012. Assumptions used in the Black Scholes option-pricing model for the year ended December 31, 2011 were as follows:

	Year Ended 12/31/2011
Average risk-free interest rate	3.35%
Average expected life- years	10
Expected volatility	94.32%
Expected dividends	0

Stock-based compensation expense includes the expense related to (1) grants of stock options, (2) grants of restricted stock, (3) stock issued as consideration for some of the services provided by our directors and strategic advisory council members, and (4) stock issued in lieu of cash to pay bonuses to our employees and contractors. We record stock-based compensation expenses in the caption with all of our other general and administrative expenses. Grants of stock options and restricted stock are awarded to our employees, directors, consultants and board members, and we recognize the fair market value of these awards ratably as they are earned. The expense related to payments in stock for services is recognized as the services are provided.

During the three months ended September 30, 2013 and 2012, approximately $60 thousand and $200 thousand respectively, were recorded as total stock-based compensation. During the nine months ended September 30, 2013 and 2012, approximately $270 thousand and $830 thousand respectively, were recorded as total stock-based compensation. Stock-based compensation expense is recorded under the caption general and administrative expenses in the accompanying consolidated statements of operations.

Note 9. Business Segment Results

We have two principal business segments, which are (1) our technology business and (2) our consulting services business. These business segments were determined based on the nature of the operations and the services offered. Operating segments are defined as components of an enterprise about which separate financial information is available that is evaluated regularly by the chief decision-makers, in deciding how to allocate resources and in assessing performance. Our Chief Executive Officer and Chief Operating Officer/Chief Financial Officer have been identified as the chief operating decision makers. Our chief operating decision makers direct the allocation of resources to operating segments based on the profitability, the cash flows, and the business plans of each respective segment.

The Company evaluates performance based on several factors, of which achievement of strategic goals toward future profitability and business segment income before taxes are the primary measures. The following tables show the operations of the Company s reportable business segments for the three months and nine months ended September 30, 2013 and 2012.

BUSINESS SEGMENT RESULTS THREE MONTHS ENDED SEPTEMBER 30, 2013 AND 2012

	Consulting		Technology		Corporate and Eliminations		Total	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenue	169,156	591,355	0	0	0	0	169,156	591,355
Segment Profit Pre Tax	(103,133)	5,532	(557,729)	(542,664)	(658,417)	(710,516)	(1,319,279)	(1,247,648)
Total Assets	628,789	420,540	672,405	580,577	1,383,090	6,405,271	2,684,284	7,406,388
Property Additions	0	0	0	0	0	0	0	0
Interest Expense	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	2,815	7,068	2,815	7,068

BUSINESS SEGMENT RESULTS NINE MONTHS ENDED SEPTEMBER 30, 2013 AND 2012

	Consulting		Technology		Corporate and Eliminations		Total	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenue	1,343,964	2,829,893	0	0	0	0	1,343,964	2,829,893
Segment Profit Pre Tax	220,875	387,192	(1,816,284)	(1,557,732)	(2,026,637)	(2,188,577)	(3,622,046)	(3,359,117)
Total Assets	628,789	420,540	672,405	580,577	1,383,090	6,405,271	2,684,284	7,406,388
Property Additions	0	0	0	0	0	18,100	0	18,100
Interest Expense	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	15,202	21,584	15,202	21,584

Note 10. Subsequent Events

We have evaluated subsequent events through the date of issuance of the financial statements, and did not have any material recognizable subsequent events, other than those listed below.

Office Lease

On October 16, 2013 we entered into a new 1 year sub-lease agreement with our current landlord for our current office space starting January 1, 2014. The monthly rent payment will be approximately $32,000 plus additional charges.

Registered Direct Offering

On October 25, 2013 the Company completed an offering (the Offering) with certain institutional investors on the sale of 2,500,000 shares of its common stock and warrants to purchase a total of 1,250,000 shares of its common stock for aggregate gross proceeds of approximately $4.4 million, before deducting fees to the Placement Agent and other estimated offering expenses payable by the Company, of approximately $0.5 million. The common stock and warrants were sold in fixed combinations, with each combination consisting of one share of common stock and a warrant to purchase 0.5 shares of common stock. The purchase price is $1.75 per fixed combination. The warrants will become exercisable six months and one day following the closing date October 25, 2013 of the Offering and will remain exercisable for 7.5 years from the date of issuance at an exercise price of $2.30 per share. The exercise price of the warrants is subject to adjustment in the case of stock splits, stock dividends, combinations of shares and similar recapitalization transactions. The exercisability of some of the warrants may be limited if, upon exercise, the holder or any of its affiliates would beneficially own more than 4.99% of the Company's common stock. This limit may be increased to up to 9.99% upon no fewer than 60 days' notice.

The Company received net proceeds of approximately $3.9 million after payment of certain fees and expenses related to the Offering. These fees and expenses related to this Offering totaled approximately $0.5 million. From the total fees and expense paid, approximately $0.3 million plus reimbursable expenses was paid to William Blair & Company, L.L.C., who served as the placement agent for the Offering. Fees and expenses approximating $0.2 million were charged to additional paid-in capital.

The Offering was effected as a takedown off the Company's shelf registration statement on Form S-3 (File No. 333-187659), which became effective on May 1, 2013 pursuant to a prospectus supplement to be filed with the Securities and Exchange Commission.

FORWARD-LOOKING STATEMENTS

In addition to historical information, this report contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. We use words such as believe , expect , anticipate project , target , plan , optimistic , intend , aim , will or similar expressions which are intended to identify forv statements. Such statements include, among others, (1) those concerning market and business segment growth, demand and acceptance of our Nuclear Energy Consulting Services and Nuclear Fuel Technology Business, (2) any projections of sales, earnings, revenue, margins or other financial items, (3) any statements of the plans, strategies and objectives of management for future operations, (4) any statements regarding future economic conditions or performance, (5) uncertainties related to conducting business in foreign countries, as well as (6) all assumptions, expectations, predictions, intentions or beliefs about future events. You are cautioned that any such forward-looking statements are not guarantees of future performance and involve risks and uncertainties, as well as assumptions that if they were to ever materialize or prove incorrect, could cause the results of the Company to differ materially from those expressed or implied by such forward-looking statements. Such risks and uncertainties, among others, include:

- our ability to attract new customers,
- our ability to employ and retain qualified employees and consultants that have experience in the Nuclear Industry,
- competition and competitive factors in the markets in which we compete,
- general economic and business conditions in the local economies in which we regularly conduct business, which can affect demand for the Company s services,
- changes in laws, rules and regulations governing our business,
- development and utilization of our intellectual property,
- potential and contingent liabilities,
- the risks identified in the Risk Factors section of this Report, and
- other risks identified in this Report.

All statements other than statements of historical fact are statements that could be deemed forward-looking statements. The Company assumes no obligation and does not intend to update these forward-looking statements, except as required by law. When used in this report, the terms Lightbridge , Company , we , our , and us r Lightbridge Corporation and its wholly-owned subsidiaries Thorium Power, Inc. (a Delaware corporation) and Lightbridge International Holding, LLC (a Delaware limited liability company).

ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management s Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, is intended to help the reader understand Lightbridge Corporation, our operations and our present business environment. MD&A is provided as a supplement to, and should be read in conjunction with, our consolidated financial statements and the accompanying notes thereto contained in Item 1. Financial Statements of this report. This overview summarizes the MD&A, which includes the following sections:

- *Our Business* a general overview of our two business segments, the material opportunities and challenges of our business;
- *Critical Accounting Policies and Estimates* a discussion of accounting policies that require critical judgments and estimates;
- *Operations Review* an analysis of our Company s consolidated results of operations for the two periods presented in our consolidated financial statements. Except to the extent that differences among our operating segments are material to an understanding of our business as a whole, we present the discussion in the MD&A on a consolidated basis; and
- *Liquidity, Capital Resources and Financial Position* an analysis of cash flows; an overview of financial position.

The following discussion contains forward-looking statements that involve risks, uncertainties, and assumptions such as statements of our plans, objectives, expectations, and intentions. Our actual results may differ materially from those discussed in these forward-looking statements because of the risks and uncertainties inherent in future events.

Our Business

We are a leading nuclear fuel technology company, and participate in the nuclear power industry in the U.S. and internationally. Our business operations can be categorized into two segments: (i) we are a developer of next generation nuclear fuel technology that has the potential to significantly uprate the power output of reactors, reducing the per-megawatt-hourly cost of generating nuclear energy, and reducing nuclear waste and proliferation, and (ii) we are a provider of nuclear power consulting and strategic advisory services to commercial and governmental entities worldwide.

Our Nuclear Fuel Technology Business Segment

We are developing innovative, proprietary nuclear fuel designs that can significantly enhance the nuclear power industry s economics and increase power output by: (1) Providing an increase in power output of up to 10% while simultaneously extending the operating cycle length from 18 to 24 months in existing pressurized water reactors (which are currently limited to an 18-month operating cycle); alternatively, the power can be increased up to 17% while retaining an 18-month operating cycle; (2) Enabling increased reactor power output (up to 30% increase) without changing the core size in new build PWRs; and (3) Reducing the volume of used fuel per kilowatt-hour as well as enhancing proliferation resistance of spent fuel. In addition, as a result of the significantly lower temperature during operation, our metallic nuclear fuel rods are expected to have improved safety margins during anticipated off-normal events. Preliminary analytical modeling shows that under a large break loss-of-coolant (LOCA) scenario, unlike conventional uranium dioxide fuel, the cladding of the Lightbridge-designed metallic fuel rods stays at least 200 degrees below 850-900 degrees Celsius which is the temperature at which steam begins to react with zirconium in the cladding generating hydrogen gas.

For uprates up to 10%, only relatively minor reactor system modifications would be required. Accordingly, we believe that nuclear utilities with existing reactor fleets may find it economically attractive to initially start with a 10% power uprate fuel variant and switch to a 17% power uprate fuel variant at the time when steam generators and other expensive plant equipment reach their lifetime limit and have to be replaced. In that case, nuclear utilities would only have to incur the incremental capital cost above and beyond the cost of standard plant equipment being replaced to accommodate a 17% power uprate in their existing PWR plants.

We believe that a major opportunity for us is the possibility that our advanced nuclear fuel designs, which are currently in the research and development stage, will be used in many existing and new light water nuclear reactors. Light water reactors are the dominant reactor type currently used in the world, and fuels for such reactors constitute the majority of the commercial market for nuclear fuel.

In response to specific feedback from Lightbridge s Nuclear Utility Fuel Advisory Board comprised of senior fuel managers from four of the larger U.S. nuclear utilities (Exelon, Duke, Dominion, and Southern Company), we have enhanced our metallic fuel assembly design for existing PWRs, eliminating the outer blanket row of oxide fuel rods and making our entire fuel assembly metallic.

As a result, nuclear utilities using our metallic fuel in existing PWRs can realize improved safety, plant economics, and operating benefits (i.e., power uprate and longer fuel cycle) without the fuel performance constraints imposed by introducing oxide fuel rods into an assembly.

On October 15, 2013, we entered into a memorandum of understanding with Babcock & Wilcox Nuclear Energy, Inc. (B&W NE), a subsidiary of The Babcock & Wilcox Company to explore joint development of a pilot-scale facility to demonstrate fabrication of Lightbridge's innovative metallic nuclear fuel.

Our goal is to enter into a definitive agreement with a fuel vendor/fabricator in early 2014.

Consulting Business Segment

We are primarily engaged in the business of assisting commercial and governmental entities with developing and expanding their nuclear industry capabilities and infrastructure. We provide integrated strategic advice across a range of expertise areas including, for example, regulatory development, nuclear reactor site selection, procurement and deployment, reactor and fuel technology, international relations and regulatory affairs. Our consulting services are expert and relationship based, with particular emphasis on key decision makers in senior positions within governments or companies, as well as focus on overall management of nuclear energy programs. To date, substantially all of our revenues are derived from our consulting and strategic advisory services business segment, which primarily provides nuclear consulting services to entities within the United Arab Emirates, our first significant consulting and strategic advisory client. In April 2010 and December 2010, we began to provide consulting services in additional countries, including the member states of the Gulf Cooperation Council (the GCC, a political and economic union that comprises the Gulf states of the Kingdom of Bahrain, State of Kuwait, Sultanate of Oman, State of Qatar, Kingdom of Saudi Arabia and United Arab Emirates) and Kuwait. We have also provided nuclear safety consulting advice to U.S. nuclear utilities.

On Oct. 7, 2013 we were selected as technical advisor to provide independent re-verification of equipment and material procurement processes related to construction and maintenance of nuclear power plants operated by Korea Hydro and Nuclear Power Company (KHNP). As a subcontractor to London-based Lloyd's Register Group Limited, we will focus on the environmental and seismic qualification and commercial grade dedication aspects of a two-year Lloyd's Register/KHNP contract.

Factors Affecting Our Financial Performance

Economics of Nuclear Power

In certain markets with a diversified energy base, decisions on new build power plants are largely affected by the economics of various energy sources. If prices of non-nuclear energy sources fall, it could limit the deployment of new build nuclear power plants in such markets. This could reduce the size of the potential markets for our fuel technology. If prices or production costs of non-nuclear energy increase, there may be increased demand for the deployment of new build nuclear power plants.

Consulting and Strategic Advisory Services

Our primary challenge in pursuing our business is that the decision making process for nuclear power programs typically involves careful consideration by many parties and therefore requires significant time. Many of the potential clients that could benefit from our services are in regions of the world where tensions surrounding nuclear energy are high, or in countries where public opinion plays an important role. Domestic and international political pressure may hinder our efforts to provide nuclear energy services, regardless of our focus on non-proliferative nuclear power.

Critical Accounting Policies and Estimates

The SEC issued Financial Reporting Release No. 60, *Cautionary Advice Regarding Disclosure About Critical Accounting Policies* suggesting that companies provide additional disclosure and commentary on their most critical accounting policies. In Financial Reporting Release No. 60, the SEC has defined the most critical accounting policies as the ones that are most important to the portrayal of a company s financial condition and operating results, and require management to make its most difficult and subjective judgments, often as a result of the need to make estimates of matters that are inherently uncertain. Based on this definition, we have identified the following significant policies as critical to the understanding of our financial statements.

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make a variety of estimates and assumptions that affect (i) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and (ii) the reported amounts of revenues and expenses during the reporting periods covered by the financial statements.

Our management expects to make judgments and estimates about the effect of matters that are inherently uncertain. As the number of variables and assumptions affecting the future resolution of the uncertainties increase, these judgments become even more subjective and complex. Although we believe that our estimates and assumptions are reasonable, actual results may differ significantly from these estimates. Changes in estimates and assumptions based upon actual results may have a material impact on our results of operations and/or financial condition. We have identified certain accounting policies that we believe are most important to the portrayal of our current financial condition and results of operations.

Accounting for Stock Based Compensation, Stock Options and Stock Granted to Employees and Non-employees

We adopted the requirements for stock-based compensation, where all forms of share-based payments to employees or non-employees, including stock options and stock purchase plans, are treated the same as any other form of compensation by recognizing the related cost in the statement of income.

Under these requirements, stock-based compensation expense for employees is measured at the grant date based on the fair value of the award, and the expense is recognized ratably over the award s vesting period.

The stock-based compensation expense incurred by Lightbridge in connection with its employees is based on the employee model of ASC 718. Under ASC 718 employee is defined as An individual over whom the grantor of a share-based compensation award exercises or has the right to exercise sufficient control to establish an employer-employee relationship based on common law as illustrated in case law and currently under U.S. tax regulations. Our advisory board members and consultants do not meet the employer-employee relationship as defined by the IRS and therefore are accounted for under ASC 505-50. Under these requirements, stock-based compensation expense for non-employees is based on the fair value of the award on the measurement date which is the earlier of the date at which a commitment for performance by the counterparty to earn the equity instruments is reached (a performance commitment), or the date at which the counterparty s performance is complete. For all grants made, we recognize compensation cost under the straight-line method.

We measure the fair value of stock options on the measurement date using a Black-Scholes option-pricing model which requires the use of several estimates, including:

- the volatility of our stock price;
- the expected life of the option;
- risk free interest rates; and
- expected dividend yield.

Prior to the completion of our merger in October 2006, we had limited historical information on the price of our stock as well as employees stock option exercise behavior for stock options issued prior to the merger. We could not rely on historical experience alone to develop assumptions for stock price volatility and the expected life of options. As such, our stock price volatility was estimated with reference to our historical stock price for the time period before the merger, from the date the announcement of the merger was made. We utilized the closing prices of our publicly-traded stock from the announcement date in January 2006 to determine our volatility and we have continued to use our historical stock price closing prices to determine our volatility.

The expected life of options is based on internal studies of historical experience and projected exercise behavior. We estimate expected forfeitures of stock-based awards at the grant date and recognize compensation cost only for those awards expected to vest. The forfeiture assumption is ultimately adjusted to the actual forfeiture rate. Estimated forfeitures are reassessed in subsequent periods and may change based on new facts and circumstances. We utilize a risk-free interest rate, which is based on the yield of U.S. treasury securities with a maturity equal to the expected life of the options. We have not and do not expect to pay dividends on our common shares.

Income Taxes

We account for income taxes using the liability method in accordance with the accounting pronouncement *Accounting for Income Taxes* , which requires the recognition of deferred tax assets or liabilities for the tax-effected temporary differences between the financial reporting and tax bases of our assets and liabilities, and for net operating loss and tax credit carry forwards. The tax expense or benefit for unusual items, prior year tax exposure items, or certain adjustments to valuation allowances are treated as discrete items in the interim period in which the events occur.

On January 1, 2007, we adopted Accounting Interpretation *Accounting for Uncertainty in Income Taxes*, which addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this requirement, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. As a result of the implementation of this standard, we did not recognize any current tax liability for unrecognized tax benefits. We do not believe that there are any unrecognized tax positions that would have a material effect on the net operating losses disclosed.

Revenue Recognition from Consulting Contracts

We believe one of our critical accounting policies is revenue recognition from our consulting contracts. We are currently primarily deriving our revenue from fees by offering consulting and strategic advisory services to commercial and government owned entities outside the U.S. planning to create or expand electricity generation capabilities, using nuclear power plants. Our fee type and structure for each client engagement depend on a number of variables, including the size of the client, the complexity, the level of the opportunity for us to improve the client s electricity generation capabilities using nuclear power plants, and other factors.

The two consulting agreements that we entered into in August 2008 with the Emirates Nuclear Energy Corporation (ENEC) and the Federal Authority for Nuclear Regulation (FANR) were fixed-fee service contracts, but were subsequently changed to time and expense contracts. We recognize revenue associated with these contracts in accordance with the time and expense billed to our customer, which is subject to their review and approval. When a loss is anticipated on a contract, the full amount of the anticipated loss is recognized immediately. Our management uses its judgment concerning the chargeable number of hours to bill under each contract considering a number of factors, including the experience of the personnel that are performing the services, the value of the services provided and the overall complexity of the project. Should changes in management s estimates be required, due to business conditions that cause the actual financial results to differ significantly from management s present estimates, revenue recognized in future periods could be adversely affected.

We recognize revenue in accordance with SEC Staff Accounting Bulletin or SAB, Topic 13, *Revenue Recognition* . We recognize revenue when all of the following conditions are met:

(1) There is persuasive evidence of an arrangement;

(2) The service has been provided to the customer;

(3) The collection of the fees is reasonably assured; and

(4) The amount of fees to be paid by the customer is fixed or determinable.

In situations where contracts include client acceptance provisions, we do not recognize revenue until such time as the client has confirmed its acceptance.

Intangibles

As presented on the accompanying balance sheet, we had patents with a net book value of approximately $0.7 million and $0.6 million as of September 30, 2013 and December 31, 2012, respectively. There are many assumptions and estimates that may directly impact the results of impairment testing, including an estimate of future expected revenues, earnings and cash flows, and discount rates applied to such expected cash flows in order to estimate fair value. We have the ability to influence the outcome and ultimate results based on the assumptions and estimates we choose for testing. To mitigate undue influence, we set criteria that are reviewed and approved by various levels of management. The determination of whether or not intangible assets have become impaired involves a significant level of judgment in the assumptions. Changes in our strategy or market conditions could significantly impact these judgments and require adjustments to recorded amounts of intangible assets.

Contingencies

Management assesses the probability of loss for certain contingencies and accrues a liability and/or discloses the relevant circumstances, as appropriate. Management discloses any liability which, taken as a whole, may have a material adverse effect on the financial condition of the Company. Refer to Note 6 to the Notes to Consolidated Financial Statements.

Recent Accounting Standards and Pronouncements

Refer to Note 1 of Notes to Consolidated Financial Statements for a discussion of recent accounting standards and pronouncements.

<u>Operations Review</u>

Business Segments and Periods Presented

We have provided a discussion of our results of operations on a consolidated basis and have also provided certain detailed segment information for each of our business segments below for the three and nine months ended September 30, 2013 and 2012, in order to provide a meaningful discussion of our business segments. We have organized our operations into two principal segments: Consulting and Nuclear Fuel Technology. We present our segment information along the same lines that our chief executives review our operating results in assessing performance and allocating resources.

BUSINESS SEGMENT RESULTS THREE MONTHS ENDED SEPTEMBER 30, 2013 AND 2012

	Consulting		Technology		Corporate and Eliminations		Total	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenue	169,156	591,355	0	0	0	0	169,156	591,355
Segment Profit Pre Tax	(103,133)	5,532	(557,729)	(542,664)	(658,417)	(710,516)	(1,319,279)	(1,247,648)
Total Assets	628,789	420,540	672,405	580,577	1,383,090	6,405,271	2,684,284	7,406,388
Property Additions	0	0	0	0	0	0	0	0
Interest Expense	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	2,815	7,068	2,815	7,068

BUSINESS SEGMENT RESULTS NINE MONTHS ENDED SEPTEMBER 30, 2013 AND 2012

	Consulting		Technology		Corporate and Eliminations		Total	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Revenue	1,343,964	2,829,893	0	0	0	0	1,343,964	2,829,893
Segment Profit Pre Tax	220,875	387,192	(1,816,284)	(1,557,732)	(2,026,637)	(2,188,577)	(3,622,046)	(3,359,117)
Total Assets	628,789	420,540	672,405	580,577	1,383,090	6,405,271	2,684,284	7,406,388
Property Additions	0	0	0	0	0	18,100	0	18,100
Interest Expense	0	0	0	0	0	0	0	0
Depreciation	0	0	0	0	15,202	21,584	15,202	21,584

Technology Business

Over the next 12 to 15 months, we expect to incur approximately $2.5 million to $3 million in research and development expenses related to the development of our proprietary nuclear fuel designs, contingent upon execution of new research and development agreements with outside contractors. We spent approximately $0.6 million and $0.5 million for research and development during the three months ended September 30, 2013 and 2012, respectively and $1.8 million and $1.6 million for the nine months ended September 30, 2013 and 2012, respectively.

Over the next 2-3 years, we expect that our research and development activities will increase and will be primarily focused on testing and demonstration of our metallic fuel technology for Western-type pressurized water reactors. The main objective of this research and development phase is to prepare for full-scale demonstration of our fuel technology in an operating commercial PWR.

Consulting Services Business

At the present time, substantially all of our revenue for the three and nine months ended September 30, 2013 and 2012, is from our consulting services business segment and is derived by offering services to governments outside of the U.S. planning to create or expand electricity generation capabilities using nuclear power plants. The fee type and structure that we offer for each client engagement is dependent on a number of variables, including the complexity of the services, the level of the opportunity for us to improve the client s electricity generation capabilities using nuclear power plants, and other factors.

Consolidated Results of Operations

The following table presents our historical operating results as a percentage of revenues for the periods indicated:

	Three Months Ended September 30,	
	2013	2012
Consolidated Statements of Income Data:		
Revenues	100 %	100 %
Costs and expenses:		
Cost of revenues	76%	63%
Gross Profit	24 %	37%
Research and development	330 %	92%
General and administrative	476 %	183%
Total expenses	806 %	275%
Loss from operations	(782)%	(238%)
Interest income and other, net	2%	27%
Loss before income taxes	(780%)	(211%)
Provision for income taxes	0%	0%
Net loss	(780%)	(211%)

Revenues

The following table presents our revenues, by business segment, for the periods presented (in millions):

	Three Months Ended September 30,	
	2013	2012
Consulting Segment Revenues:		
ENEC and FANR (UAE)	$ 0.2	$ 0.5
Other (GCC and other countries)	0.0	0.1
Total	0.2	0.6
Technology Segment Revenues	0.0	0.0
Total Revenues	$ 0.2	$ 0.6

The decrease in our revenues from 2013 to 2012 of $0.4 million resulted from the decrease in the work performed for our FANR and ENEC projects. Our consulting projects with ENEC and FANR are being performed pursuant to ongoing requests to work on specific projects on a time and expense basis as needed. The FANR contract was renegotiated in 2012 and its contract term extended to December 31, 2014. The future revenue to be earned and recognized under both the ENEC and FANR agreements will depend upon agreed upon work plans, which can differ from the revenue amounts initially planned to be earned under these agreements.

We believe that in 2013 we may obtain consulting contracts from other governments interested in deploying nuclear power in their countries, based on our commitment to providing consulting services that are relevant and objective in exploring the use of nuclear power, which in turn could increase our future consulting revenues. We have submitted proposals to several countries to provide our consulting services and we expect to hear back in the upcoming quarters as to whether we will be awarded the consulting work over other competing bids.

See Note 1 and Note 3 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report on Form 10-Q for additional information about our revenue.

Costs and Expenses

The following table presents our cost of services provided, by business segment, for the periods presented (in millions):

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
Consulting	$ 0.1	$ 0.4
Technology	0.0	0.0
Total	$ 0.1	$ 0.4

Cost of Services Provided

Cost of services provided is comprised of expenses related to the consulting, professional, administrative and other support costs allocated to our technology and consulting projects, which were incurred to perform and support the work done for our consulting projects with ENEC, FANR and our other contracts. The billing rates to us from our consultants who provide services under our consulting contracts predominantly remained the same in 2013 and 2012. The decrease in our consulting costs of $0.3 million was a result of the decrease of the work we performed for our consulting projects, as discussed above. We also used less outside consultants to perform work for us in 2013. We issued credits to our customer in September 2013 for past consulting work performed of approximately $0.1 million, resulting in a decrement of our gross profit margin percentage for the three months ended September 30, 2013 as compared to our gross profit margin percentage for the three months ended September 30, 2012.

If consulting revenues increase in future periods, we expect cost of services provided will increase in dollar amount and may increase as a percentage of revenues.

See Note 1 and Note 3 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report on Form 10-Q for additional information about our cost of services provided.

Research and Development

The following table presents our research and development expenses, (in millions):

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
Research and development expenses	$ 0.6	$ 0.5

Research and development expenses consist mostly of compensation and related costs for personnel responsible for the research and development of our fuel. The increase of $0.1 million in 2013 was primarily due to an increase in salaries and wages. All of our research and development activities are conducted in Russia and the United States. We expense research and development costs as they are incurred.

Research and development expenses will increase in dollar amount and may increase as a percentage of revenues in future periods because we expect to invest $2.5 million to $3 million in the development of our nuclear fuel products over the next 12-15 months, contingent upon execution of new research and development agreements with outside contractors. We are currently in discussions with fuel vendors/fabricators regarding entry into commercial agreements to support our research and development activities and further enhance the development of our fuel products. Though we are unable to provide a reliable estimate as to the likelihood or timing of any such commercial agreements, we hope to be able to announce significant progress in these endeavors by early 2014.

See Note 1 and Note 7 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report Form on 10-Q for additional information about our research and development costs.

General and Administrative Expenses

The following table presents our general and administrative expenses, (dollars in millions):

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
General and administrative expenses	$ 0.8	$ 1.1

General and administrative expenses consist mostly of compensation and related costs for personnel and facilities, stock-based compensation, finance, human resources, information technology, and fees for consulting and other professional services. Professional services are principally comprised of outside legal, audit, strategic advisory services and outsourcing services.

The general and administrative expenses decrease of $0.3 million was mostly related to the decrease in payroll and payroll related benefits of $0.2 million; the decrease in stock-based compensation expense of $0.1 million as a result of a significant amount of equity awards which fully vested in prior years; the reduction in consulting expenses of $0.1 million primarily due to the reduction of fees paid to our strategic advisory committee; which reduction was partially offset by an increase in other general and administrative expenses.

See Note 1 and Note 8 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report Form on 10-Q for additional information about our stock-based compensation costs.

Interest Income and Other, Net

Interest income and other income and expenses, net, decreased by approximately $0.1 million for the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. Due to a decrease in cash equivalents and marketable securities balances in 2013, we incurred a decrease in our investment income.

Provision for Income Taxes

The following table presents our provision for income taxes. Our effective tax rate for the periods presented is 40%.

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012
Provision for income taxes	$ 0.0	$ 0.0

We incurred a net loss for both 2013 and 2012, and took a 100% valuation allowance against all deferred tax assets. Therefore we did not have a provision for taxes for both 2013 and 2012.

See Note 5 of the Notes to the Condensed Consolidated Financial Statements included in this Quarterly Report on Form 10-Q for information regarding our Income Taxes.

Consolidated Results of Operations

The following table presents our historical operating results as a percentage of revenues for the periods indicated:

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Consolidated Statements of Income Data:		
Revenues	100 %	100 %
Costs and expenses:		
Cost of revenues	58%	62%
Gross Profit	42%	38%
Research and development	135%	55%
General and administrative	176%	116%

Total expenses	311%	171%
Loss from operations	(269%)	(133%)
Interest income and other, net	(1%)	14%
Loss before income taxes	(270%)	(119%)
Provision for income taxes	0%	0%
Net loss	(270%)	(119%)

26

Revenues

The following table presents our revenues, by business segment, for the periods presented (in millions):

	Nine Months Ended September 30, 2013	2012
Consulting Segment Revenues:		
ENEC and FANR (UAE)	$ 1.3	$ 2.7
Other (GCC and other countries)	0.0	0.1
Total	1.3	2.8
Technology Segment Revenues	0.0	0.0
Total Revenues	$ 1.3	$ 2.8

The decrease in our revenues from 2013 to 2012 of $1.4 million resulted from the decrease in the work performed for our FANR and ENEC projects. Our consulting projects with ENEC and FANR are being performed pursuant to ongoing requests to work on specific projects on a time and expense basis as needed. The FANR contract was renegotiated in 2012 and its contract term extended to December 31, 2014. The future revenue to be earned and recognized under both the ENEC and FANR agreements will depend upon agreed upon work plans, which can differ from the revenue amounts initially planned to be earned under these agreements.

We believe that in 2013 we may obtain consulting contracts from other governments interested in deploying nuclear power in their countries, based on our commitment to providing consulting services that are relevant and objective in exploring the use of nuclear power, which in turn could increase our future consulting revenues. We have submitted proposals to several countries to provide our consulting services and we expect to hear back in the upcoming quarters as to whether we will be awarded the consulting work over other competing bids.

See Note 1 and Note 3 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report on Form 10-Q for additional information about our revenue.

Costs and Expenses

The following table presents our cost of services provided, by business segment, for the periods presented (in millions):

	Nine Months Ended September 30, 2013	2012
Consulting	$ 0.8	$ 1.7
Technology	0.0	0.0
Total	$ 0.8	$ 1.7

Cost of Services Provided

Cost of services provided is comprised of expenses related to the consulting, professional, administrative and other support costs allocated to our technology and consulting projects, which were incurred to perform and support the work done for our consulting projects with ENEC, FANR and our other contracts. The billing rates to us from our consultants who provide services under our consulting contracts predominantly remained the same in 2013 and 2012. The decrease in our consulting costs of $0.9 million was a result of the decrease of the work we performed for our consulting projects, as discussed above. We also used less outside consultants to perform work for us in 2013, resulting in an improvement of our gross margin in 2013.

If consulting revenues increase in future periods, we expect cost of services provided will increase in dollar amount and may increase as a percentage of revenues.

See Note 1 and Note 3 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report on Form 10-Q for additional information about our cost of services provided.

Research and Development

The following table presents our research and development expenses, (in millions):

	Nine Months Ended September 30, 2013	2012
Research and development expenses	$ 1.8	$ 1.6

Research and development expenses consist mostly of compensation and related costs for personnel responsible for the research and development of our fuel. The increase of $0.2 million in 2013 was primarily due to an increase in salaries and wages. All of our research and development activities are conducted in Russia and the United States. We expense research and development costs as they are incurred.

See Note 1 and Note 7 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report Form on 10-Q for additional information about our research and development costs.

General and Administrative Expenses

The following table presents our general and administrative expenses, (dollars in millions):

	Nine Months Ended September 30, 2013	2012
General and administrative expenses	$ 2.4	$ 3.3

General and administrative expenses consist mostly of compensation and related costs for personnel and facilities, stock-based compensation, finance, human resources, information technology, and fees for consulting and other professional services. Professional services are principally comprised of outside legal, audit, strategic advisory services and outsourcing services.

The general and administrative expenses decrease of $0.9 million was mostly related to the decrease in payroll and payroll related benefits of $0.6 million; stock-based compensation expense of $0.5 million as a result of a significant amount of equity awards which fully vested in prior years; the reduction in consulting expenses of $0.2 million primarily due to the reduction of fees paid to our strategic advisory committee; which reduction was partially offset by an increase in taxes and license fees of $0.1 million, and an increase in other general and administrative expenses of $0.3 million.

See Note 1 and Note 8 of the Notes to the Condensed Consolidated Financial Statements included in Item 1 of this Quarterly Report Form on 10-Q for additional information about our stock-based compensation costs.

Interest Income and Other, Net

Interest income and other income and expenses, net, decreased by approximately $0.4 million for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. The decrease in our investment income was due to a decrease in cash equivalent and marketable securities balances in 2013.

Provision for Income Taxes

The following table presents our provision for income taxes. Our effective tax rate for the periods presented is 40%.

Nine Months Ended September 30, 2013	2012

Provision for income taxes	$ 0.0	$ 0.0

We incurred a net loss for both 2013 and 2012, and took a 100% valuation allowance against all deferred tax assets. Therefore we did not have a provision for taxes for both 2013 and 2012.

See Note 5 of the Notes to the Condensed Consolidated Financial Statements included in this Quarterly Report on Form 10-Q for information regarding our Income Taxes.

Liquidity and Capital Resources

As of September 30, 2013, we had total cash and cash equivalents and restricted cash of approximately $0.9 million. Our working capital at September 30, 2013, is approximately $1.7 million. Our present monthly cash flow shortfall, absent new consulting revenue from our current operations is approximately $475,000 per month. Based on our current cash position and absent new consulting revenue, we will need to seek new financing or additional sources of capital in early 2015 in order to fund ongoing research and development activities for our nuclear fuel technology. Our current plan is to seek external funding from third party sources to support a large portion of the remaining development, testing and demonstration activities relating to our metallic nuclear fuel technology.

On October 25, 2013 the Company completed a registered direct offering with certain institutional investors on the sale of 2,500,000 shares of its common stock and warrants to purchase a total of 1,250,000 shares of its common stock for aggregate gross proceeds of $4,375,000, before deducting fees to the Placement Agent and other estimated offering expenses payable by the Company, of approximately $0.5 million. Based on our current working capital amount and our current monthly operating cash flow shortfall, we expect to have sufficient working capital to fund our operations for the next 12 months.

The following table provides detailed information about our net cash flow for all financial statements periods presented in this Report.

Cash Flow (in millions)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net cash provided by (used in) operating activities	$ (3.3)	$ (3.7)
Net cash provided by (used in) investing activities	1.5	0.7
Net cash provided by (used in) financing activities	0.0	0.0
Net cash inflow (outflow)	$ (1.8)	$ (3.0)

Operating Activities

Cash used in operating activities for the nine months ended September 30, 2013, consisted of net loss adjusted for non-cash expense items such as depreciation and amortization, as well as the effect of changes in working capital. Cash used in operating activities for the nine months ended September 30, 2013, consisted of a net loss of $3.6 million and net adjustments for non-cash expense items totaling $0.3 million, consisting of stock-based compensation and depreciation and unrealized and realized losses on marketable securities of $0.3 million. Total cash provided by (used in) working capital totaled $0.0 million. The cash provided by (used in) working capital was due to the decrease in accounts receivable and prepaid expenses of $0.1 million offset by an increase in prepaid expenses and other assets of $0.1 million.

Cash used in operating activities in the nine months ended September 30, 2012, consists of net loss adjusted for certain non-cash expense items, such as depreciation and amortization and stock-based compensation expense, as well as the effect of changes in working capital and other activities. Cash used by operating activities in the nine months ended September 30, 2012, was approximately $3.7 million, which consisted of a net loss of $3.4 million, adjustments for non-cash expense items of $0.7 million and cash used in working capital and other activities of $1.0 million. The adjustments for non-cash expense items primarily consisted of $0.8 million of stock-based compensation expense and an unrealized gain in marketable securities of $0.1 million. In addition, the decrease in cash from changes in working capital activities primarily consisted of a decrease in accrued expenses and accounts payable of $0.6 million, primarily as a result of accrued payroll liabilities and other expenses accrued for the year ended December 31, 2011, and paid in 2012, an increase in prepaid expenses and other assets of $0.3 million, and an increase in Accounts Receivable of $0.1 million. While we continue to receive payments on all our outstanding accounts receivables, a decrease in cash receipts from our future billings may occur, which could impact cash provided by operating activities in future periods.

Investing Activities

Net cash used by our investing activities for the nine months ended September 30, 2013, as compared to net cash used by our investing activities for the same nine month period in 2012, increased by $0.8 million, due to the increase in net proceeds from the sales and purchases of marketable securities.

Financing Activities

Net cash provided by (used in) our financing activities for the nine months ended September 30, 2013, as compared to the same nine month period in 2012 was essentially the same.

Short-Term and Long-Term Liquidity Sources

In 2013 the primary potential sources of cash available to us are as follows:

1. Strategic investment through alliances with major fuel vendors, fuel fabricators and/or other strategic parties during the next three years, to support the remaining research and development activities required to further enhance and complete the development of our fuel products to a commercial stage; and

2. New consulting contracts

In support of our long-term business plan with respect to our fuel technology business, we endeavor to create strategic alliances with major fuel vendors, fuel fabricators and/or other strategic parties during the next three years, to support the remaining research and development activities required to further enhance and complete the development of our fuel products to a commercial stage. We may be unable to form such strategic alliances on terms acceptable to us or at all.

Currently, we are working on revenue opportunities with the overall goal of increasing our profitability and cash flow. We anticipate entering into consulting and technology agreements with our existing and new potential clients, which will generate additional revenues and cash flows for us in 2013 and beyond. We have written proposals out to these prospects, which as of the date of this filing are pending approval.

Although we anticipate securing new consulting work from one or more of these prospects, we cannot determine as of the date of this filing if and when new consulting contracts will be awarded to us. If we do not enter into any new consulting or technology agreements to provide working capital to support our business plan regarding our planned research and development activities for developing our fuel designs, we will need to raise additional capital in early 2015 by way of an offering of equity securities, an offering of debt securities, a financing through a bank, or a strategic alliance with another entity. We may also need to raise additional capital in early 2015 if our current consulting business segment becomes non-sustaining. We believe that if we are awarded new consulting contracts, the margin earned on these new contracts will favorably impact our short-term and long-term liquidity and will supplement the funding for our anticipated research and development expenses of our nuclear fuel technologies, of $2.5 million to $3 million over the next 12-15 months.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity or capital expenditures or capital resources that is material to an investor in our securities.

Seasonality

Our business has not been subject to any material seasonal variations in operations, although this may change in the future.

Inflation

Our business, revenues and operating results have not been affected in any material way by inflation.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not Required.

ITEM 4. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15 under the Exchange Act, we carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as of the end of the period covered by this report on Form 10-Q. This evaluation was carried out under the supervision and with the participation of our management, including our President and Chief Executive Officer, and our Chief Financial Officer. Based upon that evaluation, management concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed in the reports that it files or submits under the Exchange Act is accumulated and communicated to management (including the chief executive officer and chief financial officer) to allow timely decisions regarding required disclosure and that our disclosure controls and procedures are effective to give reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC.

Changes in Internal Controls Over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the evaluation performed that occurred during the period covered by this report that have materially affected or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls and Procedures

In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we may become involved in various lawsuits and legal proceedings which arise in the ordinary course of business. However, litigation is subject to inherent uncertainties, and an adverse result in these or other matters may arise from time to time that may harm our business. We are currently not aware of any such legal proceedings or claims that we believe will have a material adverse effect on our business, financial condition or operating results.

ITEM 1A. RISK FACTORS

Risks Associated with our Fuel Technology Business

If we are unable to enter into one or more commercial agreements with nuclear fuel fabricators and/or vendors, we may not be able to raise money on terms acceptable to us or at all.

Based on our current cash position, we will need to seek new financing or additional sources of capital in early 2015 in order to fund ongoing research and development activities for our nuclear fuel technology. New consulting revenue might be able to extend that date somewhat. Our current plan is to seek external funding from third party sources to support a large portion of the remaining development, testing and demonstration activities relating to our metallic nuclear fuel technology. We are currently in discussions with fuel vendors/fabricators regarding entry into commercial agreements to support our research and development activities and further enhance the development of our fuel products. Though we are unable to provide a reliable estimate as to the likelihood or timing of any such commercial agreements, we hope to be able to announce significant progress in these endeavors in early 2014. If we are unable to demonstrate meaningful progress towards entry into these commercial agreements or other strategic arrangements to further the development of our fuel products, it may be difficult for us to raise additional capital on terms acceptable to us or at all. If we are unable to raise additional capital in early 2015, it is unlikely that we may be able to execute our current business plan.

Our fuel designs have never been tested in an existing commercial reactor and actual fuel performance, as well as the willingness of commercial reactor operators and fuel fabricators to adopt a new design, is uncertain.

Nuclear power research and development entails significant technological risk. New designs must be fabricated, tested and licensed before they can be offered for sale in commercial markets. Our fuel designs are still in the research and development stage and while certain testing on our fuel technologies has been completed, further testing and experiments will be required in test facilities. Furthermore, the fuel technology has yet to be demonstrated in an existing commercial reactor. Until we are able to successfully demonstrate operation of our fuel designs in an actual commercial reactor, we will not be certain about the ability of the fuel we design to perform as expected. In addition, there is also a risk that suitable testing facilities may not be available to us on a timely basis, which could cause development program schedule delays.

We will also have to enter into a commercial arrangement with a fuel fabricator to actually produce fuel using our designs.

If our fuel designs do not perform as anticipated in commercial use, we will not realize revenues from licensing or other use of our fuel designs.

We serve the nuclear power industry, which is highly regulated. Our fuel designs differ from fuels currently licensed and used by commercial nuclear power plants. The regulatory licensing and approval process for our fuels may be delayed and made more costly, and industry acceptance of our fuels may be hampered.

The nuclear power industry is a highly regulated industry. All entities that operate nuclear facilities and transport nuclear materials are subject to the jurisdiction of the U.S. Nuclear Regulatory Commission, or its counterparts around the world.

Our fuel designs differ significantly in some aspects from the fuel licensed and used today by commercial nuclear power plants. These differences will likely result in more prolonged and extensive review by the U.S. Nuclear Regulatory Commission or its counterparts around the world that could cause development program schedule delays. Entities within the nuclear industry may be hesitant to be the first to use our fuel, which has little or no history of successful commercial use. Furthermore, our research and development program schedule relies on the transferability and applicability of the operating experience of the Russian icebreakers with metallic fuels for regulatory licensing purposes outside of Russia. There is a risk that if this fuel performance operating experience is found by the regulatory authority not to be transferable, more extensive experiments will be required which could cause program schedule delays and require more research and development funding.

Existing commercial nuclear infrastructure in many countries is limited to uranium material enrichments up to 5%. Our metallic fuel is enriched to higher levels which would require modifications to existing commercial nuclear infrastructure and could impede commercialization of our technology.

Existing commercial nuclear infrastructure, including conversion facilities, enrichment facilities, fabrication facilities, fuel storage facilities, fuel handling procedures, fuel operation at reactor sites, used fuel storage facilities and shipping containers, were designed and are currently licensed to handle uranium enrichment up to 5%. Our fuel designs are expected to have enrichment levels up to 19.7% and would therefore require certain modifications to existing commercial nuclear infrastructure to enable commercial nuclear facilities to handle our fuels. Those nuclear facilities will need to go through a regulatory licensing process and obtain regulatory approvals to be able to handle uranium with enrichment levels up to 19.7% and operate commercial reactors using our fuel. There is a risk that some relevant entities within the nuclear power industry may be slow in making any required facility infrastructure modifications or obtaining required licenses or approvals to handle our fuel or operate commercial reactors using our fuel. There is also a political risk associated with negative perception in certain news media and among some nuclear critics of uranium enrichments greater than 5% that could potentially delay or hinder regulatory approval of our nuclear fuel designs.

Our nuclear fuel designs rely on fabrication technologies that in certain material ways are different from the fabrication techniques presently utilized by existing commercial fuel fabricators. In particular, our metallic fuel rods must be produced using a co-extrusion fabrication process. Presently, most commercial nuclear fuel is produced using a pellet fabrication technology, whereby uranium oxide is packed into small pellets that are stacked and sealed inside metallic tubes. The co-extrusion fabrication technology involves extrusion of a single-piece solid fuel rod from a metallic matrix containing uranium and zirconium alloy. Fabrication of full-length (approximately 3.5 to 4.5 meters) metallic fuel rods has yet to be demonstrated. There is a risk that the fuel fabrication process required to produce one meter long metallic fuel rods may not be adaptable to the fabrication of full-length metallic fuel rods used in commercial reactors.

Our plans to develop our fuel designs depend on our ability to acquire the rights to the designs, data, processes and methodologies that are used or may be used in our business in the future. If we are unable to obtain such rights on reasonable terms in the future, our ability to exploit our intellectual property may be limited.

We are currently conducting fuel assembly design and testing work in Russia through our Moscow office personnel as well as Russian research institutes and other nuclear entities that are owned or are closely affiliated with the government of the Russian Federation. We do not currently possess all of the necessary know-how or have licensing or other rights to acquire or utilize certain designs, data, methodologies or processes required for the fabrication of our fuel assemblies. If we, or a fuel fabricator to whom we license our fuel technology, desire to utilize such existing processes or methodologies in the future, a license or other right to use such technologies from the Russian entities that previously developed and own such technologies would be required. Alternatively, we would have to develop our own know-how necessary for fabrication of our metallic fuel. Nuclear operators typically seek diversity of fuel supply and may be hesitant to use a fuel product that is only available from a single supplier. If we are unable to obtain a license or other right to acquire or utilize certain processes or develop our own know-how required for the fabrication of our fuel assemblies, or there is only a single supplier of our fuel assemblies, then we may not be able to fully exploit our intellectual property and may be hindered in the sale of our fuel products and services.

Our research operations are conducted primarily in Russia, making them subject to political uncertainties relating to Russia and U.S.-Russian relations.

Much of our present research activities are being conducted in Russia. Our research operations conducted in Russia are subject to various political risks and uncertainties inherent in the country of Russia. If U.S.-Russia relations deteriorate, the Russian government may decide to scale back or even cease completely its cooperation with the United States on various international projects, including nuclear power technology development programs. If this should happen, our research and development program in Russia could be scaled back or shut down, which could cause development program schedule delays and may require additional funding to access alternative testing facilities outside of Russia. The Russian institutes and other nuclear entities engaged in our project are highly regulated and, in many instances, are controlled by the Russian government. The Russian government could decide that the nuclear scientists engaged in our project in Russia or testing facilities employed in our project should be redirected to other high priority national projects in the nuclear sector which could lead to development program schedule delays. Certain future research and development activities to be performed by Russian entities under contract with us will require formal authorization from the Russian State Atomic Energy Corporation, or Rosatom , which owns those entities and is the main Russian government agency that oversees Russia's civil nuclear power industry. Rosatom requires that all collaborative projects with U.S. entities fall into one of the collaboration areas outlined in a government-to-government agreement that was entered into by and between the United States and Russia soon after the 123 Agreement on peaceful nuclear cooperation between the two countries came into force (which occurred in late 2010). Rosatom requires that the U.S. Department of Energy, or DOE, issue an official endorsement of each commercial project proposed for collaboration between a U.S. entity and Rosatom. Without such DOE endorsement and designation of the project by DOE as consistent with one of the collaboration areas outlined in the above-mentioned government-to-government agreement, Rosatom is unlikely to cooperate and participate in the proposed project. Lightbridge did receive a letter from DOE confirming that our proposed collaborative projects with Rosatom fall under the 123 agreement, which we understand has satisfied the Rosatom requirements. Until commercial negotiations with Rosatom and/or its subsidiary companies are concluded and a legally binding agreement is entered into between the parties, a risk of development program schedule delays or a lack of sufficient interest from Rosatom or its entities in proposed collaboration still remains. A lack of a legally binding agreement with Rosatom and/or its subsidiary companies may also adversely affect our ability to raise new capital at terms acceptable to us.

Applicable Russian intellectual property law may be inadequate to protect our intellectual property, which could have a material adverse effect on our business.

Intellectual property rights are evolving in Russia, trending towards international norms, but are by no means fully developed. While we are continuing to diversify our research and development activities with associated intellectual property, historically, we have worked closely with our Russian branch office employees and other Russian contractors and entities to develop a significant portion of our material intellectual property. Our rights in this intellectual property, therefore, derive, or are affected by, Russian intellectual property laws. If the application of these laws to our intellectual property rights proves inadequate, then we may not be able to fully avail ourselves of our intellectual property and our business model may fail or be significantly impeded.

If the DOE were to successfully assert that an invention claimed within our 2007 or 2008 Patent Cooperation Treaty, or PCT, patent applications was first conceived or actually reduced to practice under a contract with the DOE, then our intellectual property rights in that invention would become compromised and our business model could fail or become significantly impeded.

Work on finite aspects and/or testing of some subject matter disclosed in our 2007 and 2008 Russian PCT patent applications was done under a government contract with the DOE. If the DOE asserted that an invention claimed in the 2007 and/or 2008 Russian PCT applications was first conceived or actually reduced to practice under such a contract, and a U.S. court agreed, the DOE could gain an ownership interest in such an invention outside of the Russian Federation and our intellectual property rights in that claimed invention would become compromised and our business model may then fail or be significantly impeded.

If we are unable to obtain or maintain intellectual property rights relating to our technology, the commercial value of our technology may be adversely affected, which could in turn adversely affect our business, financial condition and results of operations.

Our success and ability to compete depends in part upon our ability to obtain protection in the United States and other countries for our nuclear fuel designs by establishing and maintaining intellectual property rights relating to or incorporated into our fuel technologies and products. We own a variety of patents and patent applications in the United States, as well as corresponding patents and patent applications in several other jurisdictions. We have not obtained patent protection in each market in which we plan to compete. We do not know how successful we would be should we choose to assert our patents against suspected infringers. Our pending and future patent applications may not issue as patents or, if issued, may not issue in a form that will be advantageous to us. Even if issued, patents may be challenged, narrowed, invalidated or circumvented, which could limit our ability to stop competitors from marketing similar products or limit the length of term of patent protection we may have for our products. Changes in either patent laws or in interpretations of patent laws in the United States and other countries may diminish the value of our intellectual property or narrow the scope of our patent protection, which could in turn adversely affect our business, financial condition and results of operations.

If we infringe or are alleged to infringe intellectual property rights of third parties, our business, financial condition and results of operations could be adversely affected.

Our nuclear fuel designs may infringe, or be claimed to infringe, patents or patent applications under which we do not hold licenses or other rights. Third parties may own or control these patents and patent applications in the United States and elsewhere. Third parties could bring claims against us that would cause us to incur substantial expenses and, if successfully asserted against us, could cause us to pay substantial damages. If a patent infringement suit were brought against us, we could be forced to stop or delay commercialization of the fuel design or a component thereof that is the subject of the suit. As a result of patent infringement claims, or in order to avoid potential claims, we may choose or be required to seek a license from the third party and be required to pay license fees, royalties or both. These licenses may not be available on acceptable terms, or at all. Even if we were able to obtain a license, the rights may be nonexclusive, which could result in our competitors gaining access to the same intellectual property. Ultimately, we could be forced to cease some aspect of our business operations if, as a result of actual or threatened patent infringement claims, we are unable to enter into licenses on acceptable terms. This could significantly and adversely affect our business, financial condition and results of operations. In addition to infringement claims against us, we may become a party to other types of patent litigation and other proceedings, including interference proceedings declared by the United States Patent and Trademark Office regarding intellectual property rights with respect to our nuclear fuel designs. The cost to us of any patent litigation or other proceeding, even if resolved in our favor, could be substantial. Some of our competitors may be able to sustain the costs of such litigation or proceedings more effectively than we can because of their greater financial resources. Uncertainties resulting from the initiation and continuation of patent litigation or other proceedings could have a material adverse effect on our ability to compete in the marketplace. Patent litigation and other proceedings may also absorb significant management time.

Our nuclear fuel process is dependent on outside suppliers of nuclear and other materials and any difficulty by a fuel fabricator in obtaining these materials could be detrimental to our ability to eventually market our fuel through a fuel fabricator.

Production of fuel assemblies using our nuclear fuel designs is dependent on the ability of fuel fabricators to obtain supplies of nuclear material utilized in our fuel assembly design. Fabricators will also need to obtain metal for components, particularly zirconium or its alloys. These materials are regulated and can be difficult to obtain or may have unfavorable pricing terms. Any difficulties in obtaining these materials by fuel fabricators could have a material adverse effect on their ability to market fuel based on our technology.

General Business Risks

If the price of non-nuclear energy sources falls, there could be an adverse impact on new build nuclear reactor activities in certain markets, which would have a material adverse effect on our operations.

In certain markets with a diversified energy base, decisions on new build power plants are largely affected by the economics of various energy sources. If prices of non-nuclear energy sources fall, it could limit the deployment of new build nuclear power plants in such markets. This could reduce the size of the potential markets for both our fuel technology and our consulting services.

We may be adversely affected by uncertainty in the global financial markets and worldwide economic downturn.

Our future results may be adversely affected by the worldwide economic downturn, continued volatility or further deterioration in the debt and equity capital markets, inflation, deflation, or other adverse economic conditions that may negatively affect us. At present, it is likely that we will require additional capital in the near future in order to fund our operations. Due to the above listed factors, we cannot be certain that additional funding will be available on terms that are acceptable to us, or at all.

We may be adversely affected by public opposition to nuclear energy as a result of the major nuclear accident at Fukushima, Japan.

The major nuclear accident at the Fukushima nuclear power plant in Japan following the massive tsunami and strong earthquake that occurred on March 11, 2011, increased public opposition to nuclear power in some countries, resulting in a slowdown in, or a complete halt to, new construction of nuclear power plants and an early shut down of existing power plants in select countries.

Our limited operating history makes it difficult to judge our prospects.

Prior to 2008, we were a development stage company. We have commenced the provision of nuclear consulting services and currently have only a limited number of clients in this area of our business. Similarly, our fuel design patents and technology have not been commercially used and we have not received any royalty or sales revenue from this area of our business. We are subject to the risks, expenses and problems frequently encountered by companies in the early stages of development.

We rely upon certain members of our senior management, including Seth Grae, and the loss of Mr. Grae or any of our senior management would have an adverse effect on the Company.

Our success depends upon certain members of our senior management, including Seth Grae, Chief Executive Officer of the Company. Mr. Grae s knowledge of the nuclear power industry, his network of key contacts within that industry and in governments and, in particular, his expertise in the potential markets for the Company s technologies, is critical to the implementation of our business model. Mr. Grae is likely to be a significant factor in our future growth and success. The loss of services by Mr. Grae would likely have a material adverse effect on our Company.

Competition for highly skilled professionals could have a material adverse effect on our success.

We rely heavily on our contractor staff and management team. Our success depends, in large part, on our ability to hire, retain, develop and motivate highly skilled professionals. Competition for these skilled professionals is intense and our inability to hire, retain and motivate adequate numbers of consultants and managers could adversely affect our ability to meet client needs and to continue the development of our fuel designs. A loss of a significant number of our employees could have a significant negative effect on us. Any significant volatility or sustained decline in the market price of our common stock could impair our ability to use equity-based compensation to attract, retain and motivate key employees and consultants.

Successful execution of our business model is dependent upon public support for nuclear power

Successful execution of our business model is dependent upon public support for nuclear power in the United States and other countries. Nuclear power faces strong opposition from certain competitive energy sources, individuals and organizations. A major nuclear accident that occurred at the Fukushima nuclear power plant in Japan that is believed to have been caused by a major tsunami wave produced by a strong earthquake that hit Japan on March 11, 2011, could have a significant adverse effect on public opinion about nuclear power and the favorable regulatory climate needed to introduce new nuclear technologies. Strong public opposition could hinder the construction of new nuclear power plants and lead to early shut-down of the existing nuclear power plants. Furthermore, nuclear fuel fabrication and the use of new nuclear fuels in reactors must be licensed by the U.S. Nuclear Regulatory Commission and equivalent governmental authorities around the world. In many countries, the licensing process includes public hearings in which opponents of the use of nuclear power might be able to cause the issuance of required licenses to be delayed or denied. Following the Fukushima nuclear accident, some countries have announced their plans to delay, scale down or cancel deployment of new nuclear power plants while others, such as Germany, have decided to completely phase out nuclear power over the coming years.

We may not be able to receive or retain authorizations that may be required for us to sell our services, or license our technology internationally.

The sales and marketing of our services and technology internationally may be subject to U.S. export control regulations and the export control laws of other countries. Governmental authorizations may be required before we can export our services or technology. If authorizations are required and not granted, our international business plans could be materially affected. The export authorization process is often time consuming. Violation of export control regulations could subject us to fines and other penalties, such as losing the ability to export for a period of years, which would limit our revenue growth opportunities and significantly hinder our attempts to expand our business internationally.

The U.S. Department of Energy (DOE) is currently finalizing its review of our Part 810 export authorization request which is required in order for us to be able to enter into an agreement relating to our proposed collaboration with Rosatom or its subsidiary companies.

Risks Associated With Our Consulting Activities.

Our inability to attract business from new clients or the loss of any of our existing clients could have a material adverse effect on us.

We expect that many of our future client engagement agreements will be terminable by our clients with little or no notice and without penalty. Some of our work may involve multiple engagements or stages. In those engagements, there is a risk that a client may choose not to retain us for additional stages of an engagement or that a client will cancel or delay additional planned engagements. In addition, a small number of existing clients account for a majority of our consulting revenues, the loss of any one of which would have a material adverse effect on our results of operations.

Our future profitability will suffer if we are not able to maintain current pricing and utilization rates.

Our revenue, and our profitability, will be largely based on the billing rates charged to clients and the number of hours our professionals will work on client engagements, which we define as the utilization of our professionals. Accordingly, if we are not able to maintain the pricing for our services or an appropriate utilization rate for our professionals, revenues, project profit margins and our future profitability will suffer. Bill rates and utilization rates are affected by a number of factors, including:

- our ability to predict future demand for services and maintain the appropriate headcount and minimize the number of underutilized personnel;
- our clients perceptions of our ability to add value through our services;
- our competitors pricing for similar services;
- the market demand for our services; and
- our ability to manage significantly larger and more diverse workforces as we increase the number of our professionals and execute our growth strategies.

Unsuccessful future client engagements could result in damage to our professional reputation or legal liability, which could have a material adverse effect on us.

Our professional reputation and that of our personnel is critical to our ability to successfully compete for new client engagements and attract or retain professionals. Any factors that damage our professional reputation could have a material adverse effect on our business.

Any client engagements that we obtain will be subject to the risk of legal liability. Any public assertion or litigation alleging that our services were negligent or that we breached any of our obligations to a client could expose us to significant legal liabilities, could distract our management and could damage our reputation. We carry professional liability insurance, but our insurance may not cover every type of claim or liability that could potentially arise from our engagements. The limits of our insurance coverage may not be enough to cover a particular claim or a group of claims, and the costs of defense.

Our results of operations could be adversely affected by disruptions in the marketplace caused by economic and political conditions.

Global economic and political conditions affect our clients businesses and the markets they serve. A severe and/or prolonged economic downturn or a negative or uncertain political climate could adversely affect our clients financial condition and the levels of business activity engaged in by our clients and the industries we serve. Clients could determine that discretionary projects are no longer viable or that new projects are not advisable. This may reduce demand for our services, depress pricing for our services or render certain services obsolete, all of which could have a material adverse effect on our results of operations. Changes in global economic conditions or the regulatory or legislative landscape could also shift demand to services for which we do not have competitive advantages, and this could negatively affect the amount of business that we are able to obtain. Although we have implemented cost management measures, if we are unable to appropriately manage costs or if we are unable to successfully anticipate changing economic and political conditions, we may be unable to effectively plan for and respond to those changes, and our business could be negatively affected.

Risks Relating to the Ownership of Our Securities

There may be volatility in our stock price, which could negatively affect investments, and stockholders may not be able to resell their shares at or above the value they originally purchased such shares.

The market price of our common stock may fluctuate significantly in response to a number of factors, some of which are beyond our control, including:

- quarterly variations in operating results;
- changes in financial estimates by securities analysts;
- changes in market valuations of other similar companies;
- announcements by us or our competitors of new products or of significant technical innovations, contracts, receipt of (or failure to obtain) government funding or support, acquisitions, strategic partnerships or joint ventures;
- additions or departures of key personnel;
- any deviations in net sales or in losses from levels expected by securities analysts, or any reduction in political support from levels expected by securities analysts;
- future sales of common stock; and
- nuclear accidents or other adverse nuclear industry events.

The stock market may experience extreme volatility that is often unrelated to the performance of particular companies. These market fluctuations may cause our stock price to fall regardless of its performance.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES OR USE OF PROCEEDS

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

There were no defaults upon senior securities during the fiscal quarter ended September 30, 2013.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

ITEM 5. OTHER INFORMATION

Not Applicable.

ITEM 6. EXHIBITS

The following exhibits are filed with this report, except those indicated as having previously been filed with the SEC and are incorporated by reference to another report, registration statement or form. As to any shareholder of record requesting a copy of this report, we will furnish any exhibit indicated in the list below as filed with this report upon payment to us of our expenses in furnishing the information.

Exhibit Number	*Description*
31.1	Rule 13a-14(a)/15d-14(a) Certification - Principal Executive Officer
31.2	Rule 13a-14(a)/15d-14(a) Certification - Principal Financial Accounting Officer
32	Section 1350 Certifications
101.INS *	XBRL Instance Document
101.SCH *	XBRL Taxonomy Extension Schema Document
101.CAL *	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF *	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB *	XBRL Taxonomy Extension Label Linkbase Document
101.PRE *	XBRL Taxonomy Extension Presentation Linkbase Document

*XBRL (Extensible Business Reporting Language) information is furnished and not filed or a part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections

SIGNATURES

In accordance with section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant caused this Report on Form 10-Q to be signed on its behalf by the undersigned, thereto duly authorized individuals.

Date: November 7, 2013

LIGHTBRIDGE CORPORATION
By: /s/ Seth Grae

Name: Seth Grae
Title: President, Chief Executive Officer and Director
(Principal Executive Officer)

By: /s/ James Guerra

Name: James Guerra
Title: Chief Operating Officer and Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

EXHIBIT INDEX

Exhibit Number	*Description*
31.1	Rule 13a-14(a)/15d-14(a) Certification - Principal Executive Officer
31.2	Rule 13a-14(a)/15d-14(a) Certification - Principal Financial Accounting Officer
32	Section 1350 Certifications
101.INS *	XBRL Instance Document
101.SCH *	XBRL Taxonomy Extension Schema Document
101.CAL *	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF *	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB *	XBRL Taxonomy Extension Label Linkbase Document
101.PRE *	XBRL Taxonomy Extension Presentation Linkbase Document

*XBRL (Extensible Business Reporting Language) information is furnished and not filed or a part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.