SEITEL INC
Form 10-K
March 14, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

OR

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

For the transition period from __________ to __________

Commission File Number 001-10165

SEITEL, INC.

(Exact name of registrant as specified in its charter)

Delaware	76-0025431
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification Number)

10811 S. Westview Circle Drive, Building C, Suite 100

Houston, Texas 77043

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code: (713) 881-8900

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

None

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

None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ¨ No x

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

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

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

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x	Smaller reporting company	¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant at March 7, 2012 was zero. On March 7, 2012 there were a total of 100 shares of common stock outstanding.

CAUTIONARY STATEMENTS CONCERNING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K (this Annual Report) contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). Statements contained in this report about our future outlook, prospects, strategies and plans, and about industry conditions, demand for seismic services and the future economic life of our seismic data are forward-looking. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical fact, are forward looking. The words proposed, anticipates, will, would, should, estimates and similar expressions are intended to identify forward-looking statements. Forward-looking statements represent our present belief and are based on our current expectations and assumptions with respect to future events. While we believe our expectations and assumptions are reasonable, they involve risks and uncertainties beyond our control that could cause the actual results or outcome to differ materially from the expected results or outcome reflected in our forward-looking statements. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Annual Report may not occur. Such risks and uncertainties include, without limitation, actual customer demand for our seismic data and related services, the timing and extent of changes in commodity prices for natural gas, crude oil and condensate and natural gas liquids, conditions in the capital markets during the periods covered by the forward-looking statements, the effect of economic conditions, our ability to obtain financing on satisfactory terms if internally generated funds and our current credit facility are insufficient to fund our capital needs, the impact on our financial condition as a result of our debt and our debt service, our ability to obtain and maintain normal terms with our vendors and service providers, our ability to maintain contracts that are critical to our operations, changes in the oil and gas industry or the economy generally and changes in the exploration budgets of our customers. Also note that we provide a cautionary discussion of risks and uncertainties under the captions Item 1A. Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report.

The forward-looking statements contained in this report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All forward-looking statements attributable to Seitel, Inc. or any person acting on its behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Annual Report and in our future periodic reports filed with the Securities and Exchange Commission (SEC).

PART I

Item 1. *Business*

General

Seitel, Inc. and its wholly owned subsidiaries are collectively referred to in this report as Seitel, the Company, we and us except as otherwise noted. Seitel is a leading provider of onshore seismic data to the oil and gas industry in North America with a top position in many of the premier unconventional plays. Seismic data significantly increases the success rate of locating and developing commercial oil and gas deposits by producing detailed images of the earth s subsurface. We own an extensive library of proprietary onshore and offshore seismic data that we license to a wide range of oil and gas companies. Our library includes a vast amount of data across many oil and gas basins and in plays, both unconventional and conventional. Unconventional plays are those that cannot be produced at economic flow rates, nor in economic volumes without the use of advanced stimulation techniques, usually for reasons of low permeability. The more common of these advanced stimulation techniques are horizontal drilling and hydraulic fracturing or any others that would enhance recovery rates. Included in these unconventional resources are heavy oil, tar sands, shale gas and oil, gas hydrates and coalbed methane. Over the past several years, we have embarked upon an aggressive campaign to acquire data in key North American unconventional plays and have established leading seismic market positions in many of those plays, including the Eagle Ford in south Texas, Marcellus in Pennsylvania, Niobrara in Colorado, Haynesville (Bossier) in east Texas, and, Montney, Cardium and Horn River in British Columbia.

Our products and services are critical for oil and gas exploration and development and management of hydrocarbon reserves by exploration and production (E&P) companies. Prior to the recent shift in activity from conventional to unconventional plays, seismic data had been used for both exploration and production purposes but with a heavy bias towards exploration. With this recent shift, customer bias has reversed and seismic data is heavily employed in production, especially in the design of horizontal drilling and fracking programs. The importance of seismic data usage in the exploration, development and management process drives demand for data in our library.

We have built a library of onshore three-dimensional (3D) seismic data that we believe is the largest available for licensing in North America. We own over 45,000 square miles of 3D and approximately 1.1 million linear miles of two-dimensional (2D) seismic data concentrated primarily in the major active North American oil and gas producing regions. Over the past several years, we have aggressively focused our acquisition activity in unconventional plays. Today, we believe we are among the most active seismic data providers (measured in square miles) in some of the more prolific unconventional plays, including the Eagle Ford, Marcellus, Niobrara, Haynesville (Bossier), Montney, Cardium and Horn River. Our library also consists of data targeted at conventional plays and shot before we embarked on our current strategy of targeting data from unconventional plays. This earlier segment of the database, although originally targeted at conventional plays, will, in some cases, coincide with more recent shale and tight sand activity occurring at the same geographic location but at a different depth. This phenomenon has driven increased sales from the earlier segment of the database and has bolstered our position as a leading seismic data provider in the newly defined unconventional plays. The early moves by our customers into unconventional plays tended to be into shale gas, and our activity matched that shift into areas such as the Haynesville, southern Eagle Ford and southern Montney. More recently, oil and gas prices have resulted in a further shift into areas that are oil prone and areas that are gas prone but with high natural gas liquids content. We also own a library of offshore data covering parts of the shelf and certain deep water areas in the Western and Central U.S. Gulf of Mexico and the waters off the coast of Eastern Canada.

We serve a market which includes over 1,600 companies in the oil and gas industry. Our customers include large independent and major integrated oil and gas companies as well as small and mid-cap exploration and production companies. Our customers hire us to acquire new seismic data for their use and typically underwrite a significant portion of the cost of the data creation in exchange for an initial license to the data. We own the acquired data and license it repeatedly to additional parties on a non-exclusive basis.

Several factors lead to multiple licensing of our seismic data. An area bounded by 3D seismic data may have multiple mineral holders with none having a single contiguous position, or a single company may not hold mineral rights throughout all depths but is restricted to one or two geological horizons. Also, new oil and gas field discoveries and/or new drilling technologies can cause renewed exploration activity in a previously assessed surrounding area and pipeline and oil and gas infrastructure expansion may make new oil and gas fields economically viable. Due to the capital intensive nature of developing unconventional plays, many oil and gas companies seek partners to share in the cost of development and these partners will often need to purchase licenses for their own use. In addition, merger and acquisition activity can change the ownership of fields often requiring re-licensing of data. Each of these factors drives repeat demand for our existing seismic library.

We regularly add to our seismic data library by creating new seismic data. These data creation programs are substantially funded by our customers in exchange for a license granting them access to the newly acquired data which may occasionally include a limited exclusivity period. We do not employ seismic crews or own any seismic survey equipment but engage, as required, multiple third party contractors with qualified equipment and expertise to shoot new data. We believe this model provides enhanced flexibility allowing us to maximize or minimize ongoing capital expenditures as necessary and results in substantially less cash flow volatility by enabling us to respond quickly to changes in demand. We also purchase seismic surveys or entire seismic libraries from oil and gas companies which have discontinued their exploration and production in a particular geographical area and no longer require ownership of, or which have otherwise determined to sell, their data or library. These purchases are funded with cash or structured as non-monetary exchanges, whereby we acquire ownership of existing data from customers in exchange for a grant of a non-exclusive license to use other data from our library. We also create new value-added products by applying advanced seismic data processing or other quantitative analytical techniques to selected portions of our library. Historically, some of our seismic data has remained useful for decades after its creation. For example, we continue to license 3D data created 18 years ago and 2D data created over 20 years ago. We expect this to continue and our data to remain useful for extended periods after its creation.

To support our seismic data licensing business and our clients, we maintain warehouse and electronic storage facilities at our Houston, Texas headquarters and our Calgary, Alberta location. Through our Seitel Solutions business unit (Solutions), we offer the ability to access and interact with the seismic data we own and market via a standard web browser and the Internet.

In 2011 and 2010, approximately 98% of our revenues were attributable to revenue generated from customers underwriting data acquisitions and revenue from licensing of seismic data. In 2009, the percentage was approximately 96%. Other revenues during these years were primarily derived from Solutions for reproduction and delivery of seismic data licensed by our clients. See Note M to Notes to Consolidated Financial Statements for information about our revenue by geographical area.

Seitel is incorporated under the laws of the State of Delaware. Our principal executive offices are in Houston, Texas.

Corporate Transactions

On February 14, 2007, Seitel Acquisition Corp. (Acquisition Corp.) was merged with and into Seitel, pursuant to a merger agreement between Seitel, Acquisition Corp. and Seitel Holdings, Inc. (Holdings) dated October 31, 2006 (the Merger). Pursuant to the merger agreement, Seitel continued as the surviving corporation and became a privately owned corporation and wholly-owned subsidiary of Holdings. Holdings is an investment entity in which ValueAct Capital Master Fund, L.P. (ValueAct Capital) owns a majority interest.

Under the terms of the merger agreement, our then existing stockholders (other than ValueAct Capital and management investors contributing certain of their shares of Seitel stock for ownership in Holdings) and option holders were paid a total consideration of $386.8 million. In connection with the Merger, the warrants held by ValueAct Capital totaling 15,037,568 were cancelled.

In connection with the Merger, Acquisition Corp. conducted a cash tender offer and consent solicitation for all of the $189.0 million aggregate principal amount of our 11.75% senior notes due 2011 (the 11.75% Senior Notes). On February 14, 2007, we paid $187.0 million aggregate principal amount for all of the notes tendered. In connection with the tender offer and consent solicitation, we entered into a supplemental indenture, supplementing the indenture dated as of July 2, 2004 with respect to the 11.75% Senior Notes. The supplemental indenture effected certain amendments to the original indenture, primarily to eliminate substantially all of the restrictive covenants and certain events of default triggered or implicated by the Merger. The remaining $2.0 million aggregate principal amount of the 11.75% Senior Notes were paid in 2011.

In addition, on February 14, 2007, we issued $400.0 million aggregate principal amount of 9.75% senior notes due 2014 (the 9.75% Senior Notes) pursuant to an indenture by and among Seitel, certain subsidiary guarantors and Bank of America, N.A. (as successor by merger to LaSalle Bank National Association), as trustee. Effective September 21, 2009, Deutsche Bank Trust Company Americas became trustee.

In May 2011, Centerbridge Capital Partners II, L.P. and Centerbridge Capital Partners SBS II, L.P. (together with Centerbridge Capital Partners II, L.P., Centerbridge) purchased a minority interest in Holdings for $125.0 million. Concurrently with the closing of this transaction, Holdings contributed $125.0 million to Seitel. The funds received were used to redeem $125.0 million of the 9.75% Senior Notes.

Description of Operations

Industry Conditions

The emergence of shale and other unconventional plays has brought about fundamental changes for the North American E&P industry. Because of advancements in horizontal drilling and fracturing technologies, unconventional plays are more economically viable at lower natural gas prices than most conventional basins in North America, which has driven a substantial increase in activity in such unconventional plays. However, the increase in natural gas supply and continuing high levels of storage have caused the price of natural gas to fall, which has driven a shift toward more oil and liquids-rich plays. The most active plays include the Eagle Ford, Niobrara and Marcellus in the United States and Montney and Cardium in Canada with several plays emerging, including the Granite Wash, Utica, Sussex and several in the Permian.

With the shift to unconventional plays, seismic data is increasingly tied to relatively stable development capital expenditures. Historically, seismic data was tied to exploration capital expenditures, which are significantly more volatile, as E&P companies used seismic data to increase the success rate of discovering hydrocarbon deposits. E&P companies now use seismic data in the shales as a development tool to better identify efficient drilling plans and maximize production by identifying and understanding a series of critical characteristics of the targeted shale.

Land rig counts in North America were strong during 2011, achieving five-year highs (based on weekly rig counts) throughout the majority of the year. Horizontal rig activity continued to represent the majority of drilling activity. In addition, there has been a shift in the mix of U.S. drilling activity from natural gas to oil given stronger oil prices and weak natural gas prices. At the end of 2011, oil directed rigs represented approximately 60% of the activity. North America drilling activity is expected to hold relatively steady to slightly increasing in 2012.

The Energy Information Administration (EIA) expects a continued tightening of world oil markets over the next two years. Based on the EIA s Short-Term Energy Outlook dated March 6, 2012, world oil consumption is projected to grow by an annual average of 1.1 million barrels per day in 2012 and 1.4 million barrels per day in 2013. The EIA expects both inventories and significant increases in the production of crude oil to meet world demand growth. Based on its March 6, 2012 report, the EIA also predicts the price of West Texas Intermediate crude oil to average about $106 per barrel in both 2012 and 2013 as compared to the average of $95 in 2011.

In this same report, the EIA projects that total natural gas consumption in 2012 will increase approximately 3.1% from 2011 and will increase approximately 1.0% from 2012 to 2013. Total marketed natural gas production grew approximately 7.9% in 2011, the largest year-over-year volumetric increase in history. While the EIA expects production growth to continue in 2012 and 2013, the projected increases occur at a much lower rate than in 2011 as low prices reduce new drilling plans. The EIA expects near-record high inventories to continue through most of 2012. Therefore, natural gas prices are not expected to increase significantly in the near term. The EIA predicts that wellhead natural gas prices will average about $2.83 per mcf in 2012 and $3.51 per mcf in 2013 as compared to the average of $3.90 per mcf in 2011.

We believe the use of 3D seismic data will continue to be an important part of oil and gas companies exploration and development spending as they are continually looking to reduce drilling risk, decrease oil and natural gas finding costs and increase the efficiencies of reservoir location, delineation, completion and management. In addition, we believe that seismic data is an essential component of oil and gas production activity in the shale plays. Seismic data can provide a wealth of insight into the shale, including areal extent, depth, thickness, faulting patterns and a number of complex rock properties. Such insights enhance our customers ability to design efficient and productive horizontal drilling and fracking programs. Understanding these unique shale features is critical for our customers as they develop their horizontal drilling plans, which can result in lateral drilling that reaches over one mile in each direction.

Seismic Data

Oil and gas companies consider seismic data an essential tool in finding and exploiting hydrocarbons. Oil and gas companies use seismic data in oil and gas exploration and development efforts to increase the probability of drilling success. Further, seismic data analysis can increase recoveries of reserves from existing, mature oil fields by optimizing the drilling location of development wells and by revealing additional, or step-out, locations that would not otherwise be apparent. With the shift to unconventional plays, E&P companies now use seismic data in the shales as a development tool to better identify efficient drilling plans and maximize production by identifying and understanding a series of critical characteristics of the targeted shale. The cost of seismic data is less than 1% of the total cost of exploration for most projects, but provides substantial benefits to operators. 3D seismic data provides a graphic depiction of the earth s subsurface from two horizontal dimensions and one vertical dimension, rendering a more detailed picture than 2D data, which presents a cross-sectional view from one vertical and one horizontal dimension. The more comprehensive geophysical information provided by 3D surveys significantly enhances an interpreter s ability to evaluate the probability of the existence and location of oil and gas deposits. However, the cost to create 3D seismic data is significantly more than the cost to create 2D seismic data. As a result, 2D data continues to be used by clients for preliminary, broad-scale exploration evaluation, as well as in determining the location and design of 3D surveys. 3D surveys can then be used for more detailed analysis to maximize actual drilling potential and success.

Although we amortize our seismic data over a maximum period of four years, most of our seismic data has continued to generate licensing revenue past its amortization period. Assuming the data is sampled and gathered adequately in the field recording phase, it is amenable to re-evaluation and re-presentation multiple times, using new or alternate processing techniques as well as updated knowledge of the Earth model.

Management believes the level of resales from various vintages of our investment in seismic data is useful in order to assess the resiliency and value of our seismic data library. Management considers estimated longevity of and foreseeable demand for data in determining whether to undertake new data acquisition projects. For the year ended December 31, 2011, resale revenue from 3D onshore data was recognized from net historical investments made in the indicated periods (in thousands):

	Resale Revenue	Percentage	Net Investment [1]	Percentage
Investments prior to 2007	$ 42,270	33%	436,343	75%
Investments 2008 through 2011	85,068	67%	143,776	25%
Total 3D onshore	$ 127,338	100%	580,119	100%

(1) Net investment reflects total data cost less client underwriting before fair value adjustments resulting from the Merger.

The following presents a reconciliation of resale revenue for 3D onshore (a non-GAAP financial measure) to total revenue for the year ended December 31, 2011 (the most directly comparable GAAP financial measure) (in thousands):

Total resale revenue 3D onshore	$ 127,338
Other revenue components:	
Other resale revenue (principally offshore and 2D)	8,912
Acquisition revenue	77,406
Solutions and other revenue	4,352
Total revenue	$ 218,008

The following presents a reconciliation of net historical investment for 3D onshore data (a non-GAAP financial measure) to net book value at December 31, 2011 (the most directly comparable GAAP financial measure) (in thousands):

Net historical investment in seismic data 3D onshore	$ 580,119
Add:	
Acquisition revenue 3D onshore	601,838
Other seismic data investment (principally offshore and 2D)	385,971
Foreign currency translation	40,166
Seismic projects in progress	67,743
Fair value adjustment resulting from Merger	275,235
Less:	
Historical impairment charges	(112,923)
Accumulated amortization (including historical amounts pre-Merger)	(1,717,455)
Net book value	$ 120,694

Seismic Data Library

Our seismic data library includes onshore and offshore 3D data, 2D data and multi-component data. We have ownership in over 45,000 square miles of 3D and approximately 1.1 million linear miles of 2D seismic data concentrated primarily in the major North American oil and natural gas producing regions. Over the past several years, we have aggressively focused our acquisition activity on unconventional plays. Today, we believe we are among the most active seismic data providers (measured in square miles) in some of the more prolific unconventional plays, including the Eagle Ford, Marcellus, Niobrara, Haynesville (Bossier), Montney, Cardium and Horn River. Our library also consists of data targeted at conventional plays and shot before we embarked on our current strategy of targeting data from unconventional plays. We also own a library of offshore data covering parts of the shelf and certain deep water areas in the Western and Central U.S. Gulf of Mexico and the waters off the coast of Eastern Canada. The following table describes our 3D seismic data library, as well as data that we manage and market for third parties, as of March 7, 2012:

3D Data Library	Completed Surveys Square Miles[(1)]	Completed Surveys Percentage of Subtotal	Surveys in Progress Square Miles [(1)]
Haynesville	1,350	6%	
Eagle Ford	4,000	18%	750
Niobrara/Bakken	2,100	9%	250
Marcellus and Utica	150	1%	600
Granite Wash		0%	350
Conventional 3D	15,200	66%	
Total U.S. Onshore	22,800	100%	1,950
Montney	3,400	28%	250
Horn River	1,050	8%	
Cardium	2,900	23%	50
Conventional 3D	5,100	41%	
Total Canada	12,450	100%	300
U.S. Offshore	10,500	100%	
Worldwide Total	45,750	100%	2,250

(1) Square miles reflect mileage net to our revenue interest.

Onshore U.S. and Canada: Since 2008, our capital Investment in both the U.S. and Canada has been focused on unconventional plays, initially in the shale gas areas and more recently shifting towards oil and liquids-rich objectives. These shifts in focus are made in accordance with the activity of our clients and our ability to serve them is an important component of our growth strategy.

The U.S. onshore 3D conventional sector of our seismic data library is mainly comprised of our Gulf Coast Texas and southern Louisiana/Mississippi components, which we began accumulating in 1993. We also have relatively small amounts of 3D seismic data in other areas, such as Alabama, California, Michigan, Northern Louisiana and West Texas as well as an extensive 2D data library that continues to contribute to our licensing sales.

The Canadian onshore 3D conventional sector of our seismic data library is mainly comprised of data within the Western Canadian Basin, which we began accumulating in 1998. We also have an extensive 2D data library that continues to contribute to our licensing sales.

Offshore U.S. Gulf of Mexico: Our library of offshore data covers parts of the U.S. Gulf of Mexico shelf and certain deep water areas in the Western and Central U.S. Gulf of Mexico. We have accumulated our U.S. Gulf of Mexico offshore 3D data since 1993. Although we have not shot new offshore surveys since 2002, on occasion, we add offshore Gulf of Mexico data through non-monetary exchanges.

Data Library Growth

We regularly add to our library of seismic data by: (1) recording new data, (2) buying ownership of existing data for cash, (3) acquiring ownership of existing data through non-monetary exchanges or (4) creating new value-added products from data existing within our library.

Underwritten Data Acquisitions: We create new seismic data designed in conjunction with our customers and specifically suited to the geology and environmental conditions of the area using the most appropriate technology available. Typically, one or more customers will underwrite or fund a significant portion of the direct cost in exchange for a license or licenses to use the resulting data. Under the terms of these licenses, the customers may occasionally have a limited exclusivity period. We consider the contracts signed up to the time we make a firm commitment to create the new seismic survey as underwriting or pre-funding. Any subsequent licensing of the data while it is in progress or once it is completed is considered a resale license. All of our data acquisition activity during 2011 occurred in unconventional plays, primarily the Eagle Ford in Texas, Marcellus in Pennsylvania, Niobrara in Colorado and both Montney and Cardium in Western Canada. All field work on these projects is outsourced to subcontractors. A significant percentage of the data processing for our U.S. projects is processed by our wholly owned subsidiary Seitel Data Processing, Inc. To date, all of the data processing for our Canadian projects has been outsourced to local subcontractors. In the first quarter of 2012, we began to form an internal data processing group in Canada with the intent that, over time, this group will grow to parallel the U.S. group and will undertake a high percentage of the processing work on our Canadian projects. We employ experienced geoscientists who design seismic programs and oversee field acquisition and data processing to ensure the quality and longevity of the data created.

Cash Purchases**:** We purchase seismic data for cash from oil and gas companies, other seismic companies or financial investors in seismic data when opportunities arise and that meet our investment criteria.

Non-Monetary Exchanges: We grant our customers a non-exclusive license to selected data from our library in exchange for ownership of seismic data from the customer, a non-monetary exchange. The data that we receive is distinct from the data that is licensed to the customer. These transactions will tend to be for individual surveys or groups of surveys. We also use non-monetary exchanges in conjunction with data acquisitions and cash purchases. In addition, we may receive advanced data processing services on selected existing data in exchange for a non-exclusive license to selected data from our library.

Value-Added Products**:** We create new products from existing seismic surveys in our library by extracting a variety of additional information from surveys that was not readily apparent in the initial products. Opportunities to extract such additional information and create such additional products may result from information from secondary sources, alternative conclusions regarding the initial products and applying alternate or more complex processes to the initial products, or some combination of these factors. Additional products may include Pre-Stack Time Migration volumes, Amplitude Versus Offset volumes, Complex Attribute volumes, Rock Property volumes and Pre-Stack Depth Migration volumes. Typically, one or more customers will underwrite a portion of the direct cost involved in these products in exchange for a license or licenses to use the resulting data. Under these licenses, the customers may have exclusive access to the newly acquired data for a limited term. After this limited term of exclusivity, the data is added to our library for licensing to the industry on a non-exclusive basis. Work on these projects may be performed by Seitel Data Processing, Inc., outsourced to specific specialists in the arena or conducted under an alliance with a particular specialist. We employ experienced geoscientists who design these value-added products and oversee the processing to ensure the quality and longevity of the data created.

Licenses and Marketing

We actively market data from our library to customers under non-exclusive license agreements using a well-developed marketing strategy combined with strong geophysical expertise. Our licenses are generally non-assignable and typically provide that in the event of a change of control of a customer-licensee, the surviving entity must pay a fee to maintain a license for any data it seeks to continue to use and for which such entity previously did not have a license. We employ an experienced sales force and it is our operating philosophy to actively market our seismic library. Our team of dedicated marketing specialists seeks to maximize license sale opportunities by monitoring petroleum industry exploration and development activities through close interaction with oil and gas companies on a daily basis. Our marketing team develops innovative contracting methods that have expanded the market for seismic data to our customers.

Licenses generally are granted for cash, payable within 30 days of invoice, although we sometimes permit a customer to make an initial payment upon inception of the license followed by periodic payments over time, usually not more than 12 months. Some licenses provide for additional payments to us if the licensee acquires additional mineral leases, drills wells or achieves oil or gas production in the areas covered by the licensed data.

Fundamental to our business model is the concept that once seismic data is created it is owned by us and added to our library for licensing to customers in the oil and gas industry on a non-exclusive basis. Since the data is a long lived asset, such data can be licensed repeatedly and over an extended period of time to different customers.

Backlog

At March 7, 2012, we had capital expenditure commitments related to data creation projects of approximately $165.7 million of which we have obtained approximately $100.9 million of underwriting. We anticipate that the majority of this backlog will be recognized over the next 12 months. This is compared to capital expenditure commitments at March 10, 2011 of $103.3 million with underwriting of approximately $64.0 million.

Seitel Solutions

To support our seismic data licensing business and our clients, we maintain warehouse and electronic storage facilities at our Houston, Texas headquarters and our Calgary, Alberta location. Through our Solutions business unit, we offer the ability to access and interact with the seismic data we own and market via a standard web browser and the Internet. Using proprietary technology, we store, manage, access and deliver data, tapes and graphic cross-sections to our licensees. In addition, Solutions offers use of its proprietary display and inventory software to certain customers, and the use of its proprietary quality control software to the seismic brokerage community principally in Calgary, Alberta, Canada. We also offer data management services to select clients.

Customers

We market our seismic data to a varied customer base. Our customers include independent oil and gas companies, major integrated oil and gas companies and national oil companies, as well as small and mid-cap exploration and production companies and private prospect generating individuals. One customer accounted for approximately 11% of our revenue during the year ended December 31, 2011. No one customer accounted for more than 10% of revenue during the years ended December 31, 2010 and 2009. We believe that the quality of our data, the breadth of its coverage in the major active North American basins and our longstanding commitment to client service enables us to attract top-tier clients. Because we do not acquire data speculatively, strategic relationships with our customers have been and will continue to be critical to our growth. We do not believe that the loss of any single customer would have a material adverse impact on our seismic business, cash flows or results of operations.

Competition

The creation and licensing of seismic data is competitive. Customers consider several factors, including location of data, price, technological expertise and reputation for quality and dependability, when choosing a service provider. There are a number of geophysical companies that create, market and license seismic data and maintain seismic data libraries. Rather than outsourcing their seismic data activities, some oil and gas companies create their own seismic data libraries, which they license to others. Our largest competitors, many of whom are engaged in acquiring seismic data, as well as maintaining a data library, are CGGVeritas; Geokinetics, Inc.; Global Geophysical Services, Inc.; Pulse Seismic Inc.; Seismic Exchange, Inc. (a private company based in New Orleans, Louisiana); TGS Nopec; and WesternGeco. Many of our competitors have substantially larger revenues and resources than we do.

Regulation

Our operations are subject to a variety of federal, provincial, state, foreign and local laws and regulations, including environmental and health and safety laws. We invest financial and managerial resources to comply with these laws and related permit requirements. Various governmental authorities have the power to enforce compliance with these regulations and the permits issued under them, and violators are subject to administrative, civil and criminal penalties, including civil fines, injunctions or both. In addition, failure to timely obtain required permits may result in delays in acquiring new data for our data library or cause operating losses. Because these laws and our business may change from time to time, we cannot predict the future cost of complying with these laws, and expenditures to ensure our compliance could be material in the future. Modification of existing laws or regulations or adoption of new laws or regulations limiting exploration or production activities by oil and gas companies could adversely affect us by reducing the demand for our seismic data.

Seasonality and Timing Factors

Our results of operations fluctuate from quarter to quarter due to a number of factors. Our results are influenced by oil and gas industry capital expenditure budgets and spending patterns. These budgets are not necessarily spent in equal or progressive increments during the year, with spending patterns affected by individual oil and gas company requirements as well as industry-wide conditions. In addition, under our revenue recognition policy, revenue recognition from data licensing contracts is dependent upon, among other things, when the customer selects the data or when the data becomes available for delivery. As a result, our seismic data revenue does not necessarily flow evenly or progressively during a year or from year to year. Although the majority of our data licensing transactions provide for fees to us of under $750,000 per transaction, occasionally a single data license transaction from our library, including those resulting from the merger and acquisition or property sales activity of our customers, may be substantially larger. Such large license transactions, the completion and delivery of data or an unusually large number of, or reduction in, data selections by customers can materially impact our results during a quarter, creating an impression of a revenue trend that may not be repeated in subsequent periods. In our data creation activities, weather-related or other events outside our control may impact or delay surveys during any given quarter.

Employees

As of December 31, 2011, we and our subsidiaries had 118 full-time employees, including 5 executive officers,17 marketing staff and 33 geotechnical staff. None of our employees are covered by collective bargaining agreements, and we consider our relationship with our employees to be good.

Raw Material and Proprietary Information

We are not dependent on any particular raw materials, patents, trademarks or copyrights for our business operations. Our seismic data library is proprietary confidential information, which is not generally available to the public. The seismic data within our library is protected through confidentiality agreements with our employees and licensees. We believe that our seismic data library is also protected by common law copyright.

Available Information

We make available free of charge, or through the "Investor Relations" section of our website at www.seitel.com, access to our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is filed with, or furnished to, the SEC. Our Code of Business Conduct and Ethics is also available through the "Investor Relations-Corporate Governance" section of our website or in print to anyone who requests them.

The public may read and copy any materials filed by us with the SEC at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549 and may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov.

Item 1A. *Risk Factors*

Our industry is cyclical and our business could be adversely affected by the level of capital expenditures by oil and gas companies and by the level and volatility of oil and natural gas prices.

Our industry and the oil and gas industry generally are subject to cyclical fluctuations. Demand for our services depends upon spending levels by oil and gas companies for exploration, production, development and field

management of oil and natural gas reserves and, in the case of new seismic data creation, the willingness of these companies to forgo ownership in the seismic data. Capital expenditures by oil and gas companies for these activities depend upon several factors, including actual and forecasted prices of oil and natural gas and those companies short-term and strategic plans. Oil and natural gas prices in turn depend on local, regional and global events or conditions that affect supply and demand for the relevant commodity. These events or conditions are generally not predictable and include, among other things:

- levels of demand for, and production of, oil and natural gas;
- worldwide political, military and economic conditions, including social and political unrest in Africa and the Middle East;
- weather, including seasonal patterns that affect regional energy demand as well as severe weather events that can disrupt supply;
- the level of oil and natural gas reserves; and
- government policies regarding adherence to OPEC quotas.

Oil and natural gas prices are subject to significant volatility and there can be no assurance that oil and natural gas prices and demand will not decline in the future. Low oil and natural gas prices and demand could result in decreased exploration and development spending by oil and gas companies, which could, in turn, affect our seismic data business. Our customers may adjust their exploration and development spending levels very quickly in response to any material change in oil and natural gas prices. Continued political instability (especially in the Middle East and other oil-producing regions) may lead to further significant fluctuations in demand and pricing for oil and gas or seismic data. Any future decline in oil and natural gas prices, sustained downturn in the oil and gas or seismic data industries, or sustained periods of reduced capital expenditures by oil and gas companies as a result of factors which are beyond our control could have a material adverse effect on our results of operations and cash flow.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the demand for our seismic data and related services.

Hydraulic fracturing is a process used by oil and gas exploration and production operators in the completion of certain oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. Due to concerns that hydraulic fracturing may adversely affect drinking water supplies, the U.S. Environmental Protection Agency (EPA) is undertaking a comprehensive research study to investigate any potential adverse impact that hydraulic fracturing may have on water quality and public health. The initial study results are expected to be available in 2012. An additional report is expected to be available in 2014. The EPA also has indicated that it intends to regulate hydraulic fracturing utilizing diesel fuels under its underground injection control permitting program, announced plans to develop standards for discharges of hydraulic fracturing wastewaters, proposed air standards for certain hydraulic fracturing operations and initiated a process for collecting health information and other data about fracturing additives. Separately, the U.S. Department of the Interior has announced plans to develop new rules for hydraulic fracturing on public lands that would address disclosure of chemicals used in the process, well bore integrity and handling of flowback water. Aside from these federal initiatives, several state and local governments have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely. In certain areas of the country, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays and/or increase operating costs and additional regulatory burdens on operators, which could reduce their production of natural gas and, in turn, adversely affect our revenues and results of operations by decreasing the demand for our seismic data and related services.

Economic conditions could adversely affect demand for our seismic data and related services and may increase our credit risk of customer non-payment.

Prices for oil and natural gas have been volatile. Commencing in late 2008, commodity prices for oil and natural gas declined significantly. Crude oil prices recovered during 2010 while natural gas prices improved but continue to be depressed. A return to lower crude oil prices and continuing low natural gas prices could result in many oil and gas companies significantly reducing their levels of capital spending which could result in reduced demand for our seismic data and related services as our customers' operating cash flow decreases and the borrowing bases under their oil and gas reserve-based credit facilities are reduced. Lower commodity prices could also result in decreases in our customers liquidity and capital resources which could increase our credit risk of non-payment from such customers.

We are dependent on the availability of internally generated cash flow and financing alternatives to cover the costs of acquiring and processing seismic data for our data library that are not underwritten by our customers.

We continue to invest additional capital in acquiring and processing new seismic data to add to our data library and as our business grows, we expect these investments to increase. A significant portion of these costs are underwritten by our customers, while the remainder is financed through the use of internally generated cash flow and other financing sources. We may use bank or commercial debt, the issuance of equity or debt securities or any combination thereof to finance these costs. There can be no assurance that our customers will continue to underwrite these costs at historical levels, or that we will have available internally generated funds or will be successful in obtaining sufficient capital through additional financing or other transactions, if and when required on terms acceptable to us, to continue to invest in acquiring new seismic data. Any substantial alteration of or increase in our capitalization through the issuance of debt securities may significantly increase our leverage and decrease our financial flexibility. If we are unable to obtain financing if and when needed, we may be forced to curtail our business objectives and to finance business activities with only internally generated funds as may then be available.

Our substantial level of indebtedness could adversely affect our financial condition and our ability to fulfill our obligations and operate our business.

We have a significant amount of leverage and interest expense. As of December 31, 2011, we had approximately $278.3 million of total outstanding indebtedness, including $3.2 million of capital leases. In addition, we have $30.0 million available for borrowing under our revolving credit facility, none of which was drawn at December 31, 2011. Our 2012 consolidated annual debt service requirements are expected to aggregate approximately $27.3 million. We may also incur additional indebtedness in the future.

Our high level of indebtedness could have negative consequences to us, including:

- we may have difficulty satisfying our obligations with respect to our debt;
- we may have difficulty obtaining financing in the future for working capital, capital expenditures, acquisitions or other purposes;
- we may need to use all, or a substantial portion, of our available cash flow to pay interest and principal on our debt, which will reduce the amount of money available to finance our operations and other business activities;
- our vulnerability to general economic downturns and adverse industry conditions could increase;
- our flexibility in planning for, or reacting to, changes in our business and in our industry in general could be limited;
- our substantial amount of debt and the amount we must pay to service our debt obligations could place us at a competitive disadvantage compared to our competitors that have less debt;
- our customers may react adversely to our significant debt level and seek or develop alternative licensors or suppliers;

we may have insufficient funds, and our debt level may also restrict us from raising the funds necessary to repurchase all of the notes tendered to us upon the occurrence of a change of control, which would constitute an event of default under the notes; and

our failure to comply with the restrictive covenants in our debt instruments which, among other things, limit our ability to incur debt and sell assets, could result in an event of default that, if not cured or waived, could have a material adverse effect on our business or prospects.

Our high level of indebtedness requires that we use a substantial portion of our cash flow from operations to pay principal of, and interest on, our indebtedness, which will reduce the availability of cash to fund working capital requirements, capital expenditures, research and development and other general corporate or business activities, including future acquisitions.

In addition, our revolving credit facility bears interest at variable rates. If market interest rates increase, debt service on our credit facility will rise, which would adversely affect our cash flow. Although we may employ hedging strategies such that a portion of the aggregate principal amount of this credit facility carries a fixed rate of interest, any hedging arrangement put in place may not offer complete protection from this risk. Additionally, the remaining portion of this credit facility may not be hedged and, accordingly, the portion that is not hedged will be subject to changes in interest rates.

Our business could be adversely affected by the failure of our customers to fulfill their obligations to reimburse us for the underwritten portion of third-party contractor costs.

A substantial portion of our seismic acquisition project costs, including third-party project costs, are underwritten by our customers. We target an average of 60% to 65% underwriting levels for new seismic acquisition projects on an aggregate basis. On occasion, when our underwriting customer owns other attractive seismic data that we want to obtain, we may decide to take ownership in this data to cover part of the customer s underwriting obligation. In the event that underwriters for such projects fail to fulfill their obligations with respect to such underwriting commitments, we would continue to be obligated to satisfy our payment obligations to third-party contractors.

Competition for the acquisition of new seismic data is intense.

There are a number of geophysical companies that create, market and license seismic data and maintain seismic libraries. Competition for acquisition of new seismic data among geophysical service providers historically has been, and we expect will continue to be, intense. Certain competitors have significantly greater financial and other resources than we do. These larger and better-financed operators could enjoy an advantage over us in a competitive environment for new data.

Our operating results and cash flows are subject to fluctuations due to circumstances that are beyond our control.

Our operating results and cash flows from operations have in the past, and may in the future, vary in material respects from period to period. Factors that have and could cause variations include (1) timing of the receipt and commencement of contracts for data acquisition, (2) our customers budgetary cycles and their effect on the demand for geophysical activities, (3) seasonal factors, (4) the timing of sales of licenses and selections of significant geophysical data from our data library, which are not typically made in a linear or consistent pattern and (5) technological or regulatory changes. These revenue fluctuations could produce unexpected adverse operating results in any period.

Reduced demand for our seismic data may result in an impairment of the value of our seismic data library.

Reduced demand, future sales or cash flows may result in a requirement to increase amortization rates or record impairment charges to reduce the carrying value of our data library. Such increases or charges, if required, could be material to operating results in the periods in which they are recorded. For purposes of evaluating potential impairment losses, we estimate the future cash flows attributable to a library component by evaluating historical and recent revenue trends, oil and gas prospectivity in particular regions, general economic conditions affecting our customer base, expected changes in technology and other factors that we deem relevant. As a result of these factors, among others, estimations of future cash flows are highly subjective, inherently imprecise and can fluctuate materially from period to period. Accordingly, if conditions change in the future, we may record impairment losses relative to our seismic data library, which could materially affect our results of operations in any particular reporting period.

Failure to meet cash flow projections may result in goodwill impairment charges.

We perform an annual assessment of the recoverability of goodwill by applying qualitative procedures. Additionally, we assess goodwill for impairment whenever events or changes in circumstances indicate that such carrying values may not be recoverable. If required to perform a goodwill impairment test, we rely on discounted cash flow analysis, which requires significant judgments and estimates about our future operations, to develop our estimates of fair value. If these projected cash flows change materially, we may be required to record impairment losses relative to goodwill which could be material to our results of operations in any particular reporting period.

Our Canadian operations subject us to currency translation risk, which could cause our results to fluctuate significantly from period to period.

A portion of our revenues are derived from our Canadian activities and operations. As a result, we translate the results of our operations and financial condition of our Canadian operations into U.S. dollars. Therefore, our reported results of operations and financial condition are subject to changes in the exchange rate between the two currencies. Fluctuations in foreign currency exchange rates could affect our revenue, expenses and operating margins. Assets and liabilities of Canadian operations are translated from Canadian dollars into U.S. dollars at the exchange rates in effect at the relevant balance sheet date, and revenue and expenses of Canadian operations are translated from Canadian dollars into U.S. dollars at exchange rates as of the dates on which they are recognized. Translation adjustments related to assets and liabilities are included in accumulated other comprehensive income (loss) in stockholder's equity. Realized gains and losses on translation of the Canadian operations into U.S. dollars are included in net income (loss). Currently, we do not hedge our exposure to changes in foreign exchange rates.

We may be unable to attract and retain key employees.

Our success depends upon attracting and retaining highly skilled geophysical professionals and other technical personnel. A failure to continue to attract and retain these individuals could adversely affect our ability to compete in the geophysical services industry. We may confront significant and potentially adverse competition for key personnel, particularly during periods of increased demand for geophysical services.

Our success also depends to a significant extent upon the abilities and efforts of members of our senior management, the loss of whom could adversely affect our business. Senior executives, which includes our President and Chief Executive Officer, Chief Operating Officer, Chief Financial Officer, General Counsel, President of Seitel Data, Ltd. and President of Olympic Seismic Ltd., have employment agreements with us. We cannot be certain that our senior executives will continue to be employed by us for an indefinite period of time and, if they do, how long they will remain so employed. Our inability to attract and retain key personnel could have a material adverse effect on our ability to manage our business properly.

Current and future government regulation may negatively impact demand for our products and services and increase our cost of conducting business.

The conduct of our business and the use of our products and services are subject to various laws and regulations administered by federal, state and local governmental agencies in the United States and Canada. These laws and regulations may impose numerous obligations that are applicable to our operations including:

- the acquisition of permits before commencing regulated activities; and

- the limitation or prohibition of seismic activities in environmentally sensitive or protected areas such as wetlands or wilderness areas.

Failure to comply with laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. Additionally, these laws and regulations may change as a result of political, economic or social events. Changes in laws, regulations or governmental policy may alter the environment in which we do business and the demand for our products and services and, therefore, may impact our results of operations or increase our liabilities. Changes in these and other laws and regulations or additional regulation could cause the demand for our products to decrease. Moreover, complying with increased or changed regulations could cause our operating expenses to increase, which could adversely affect our business.

Technological changes not available to us could adversely affect our business.

New data acquisition or processing technologies may be developed. New and enhanced products and services introduced by one of our competitors may gain market acceptance, and, if not available to us, may adversely affect us.

The indenture governing our $275.0 million aggregate principal amount of 9.75% Senior Notes contains a number of restrictive covenants which limit our ability to finance future operations or capital needs or engage in other business activities that may be in our interest.

The indenture governing our 9.75% Senior Notes imposes, and the terms of any future indebtedness may impose, operating and other restrictions on us and our subsidiaries. Such restrictions affect or will affect, and in many respects limit or prohibit, among other things, our ability and the ability of certain of our subsidiaries to:

- incur additional indebtedness;
- create liens;
- pay dividends and make other distributions in respect of our capital stock;
- redeem our capital stock;
- make investments or certain other restricted payments;
- sell certain kinds of assets;
- enter into transactions with affiliates; and
- effect mergers or consolidations.

The restrictions contained in the indenture governing our 9.75% Senior Notes could:

- limit our ability to plan for or react to market or economic conditions or meet capital needs or otherwise restrict our activities or business plans; and
- adversely affect our ability to finance our operations, acquisitions, investments or strategic alliances or other capital needs or to engage in other business activities that would be in our interest.

A breach of any of these covenants could result in a default under the indenture governing our 9.75% Senior Notes. If an event of default occurs, the lenders could elect to:

- declare all borrowings outstanding, together with accrued and unpaid interest, to be immediately due and payable; or
- require us to apply all of our available cash to repay the borrowings.

If we were unable to repay or otherwise refinance these borrowings when due, we cannot assure you that sufficient assets will remain to repay the 9.75% Senior Notes.

Our internal controls for financial reporting and our disclosure controls and procedures may not prevent all possible errors that could occur.

Our Chief Executive Officer and Chief Financial Officer evaluate on a quarterly basis our internal controls for financial reporting and our disclosure controls and procedures, which includes a review of the objectives, design, implementation and effect of the controls in respect of the information generated for use in our periodic reports. In the course of our controls evaluation, we seek to identify data errors, control problems and to confirm that appropriate corrective action, including process improvements, were being undertaken. The overall goals of these various evaluation activities are to monitor our internal controls for financial reporting and our disclosure controls and procedures and to make modifications as necessary. Our intent in this regard is that our internal controls for financial reporting and our disclosure controls and procedures will be maintained as dynamic systems that change (including with improvements and corrections) as conditions warrant.

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system s objectives will be satisfied. Our management has concluded that our internal controls for financial reporting and our disclosure controls and procedures are designed to give a reasonable assurance that they are effective to achieve their objectives. We cannot provide absolute assurance that we have detected all possible control issues. These inherent limitations include the possibility that judgments in our decision-making could be faulty, and that isolated breakdowns could occur because of simple human error or mistake. The design of our system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed absolutely in achieving our stated goals under all potential future or unforeseeable conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud could occur and not be detected. Breakdowns in our internal controls and procedures could occur in the future, and any such breakdowns could have an adverse effect on us.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our corporate headquarters are located at 10811 South Westview Circle Drive, Suite 100, Building C, Houston, Texas 77043, which also serves as administrative and financial offices and warehouse space and storage. We maintain domestic marketing offices in Denver, Colorado; New Orleans, Louisiana and Oklahoma City, Oklahoma. We also lease office and warehouse space in two separate locations in Calgary, Alberta, Canada, where our Canadian operations are headquartered. We consider our business facilities adequate and suitable for our present and anticipated future needs, but may seek to expand our facilities from time to time.

The following table sets forth the locations of our offices and warehouses, the approximate square footage of space we maintain at such locations, our use of such space and whether it is owned or leased by us.

Location	Approximate Square Footage	Use	Owned/Leased
Houston, Texas	80,125	Administrative; Financial; Marketing; Operations; Warehouse	Leased
Denver, Colorado	1,513	Marketing	Leased
New Orleans, Louisiana	364	Marketing	Leased
Oklahoma City, Oklahoma	234	Marketing	Leased
Calgary, Alberta, Canada [a]	23,270	Administrative; Financial; Marketing; Operations	Leased
Calgary, Alberta, Canada	42,985	Warehouse	Leased

(a) We have subleased 11,635 square feet of this office space to a third party through the end of our lease term.

Item 3. ***Legal Proceedings***

We are involved from time to time in ordinary, routine claims and lawsuits incidental to our business. In the opinion of management, uninsured losses, if any, resulting from the ultimate resolutions of these matters should not be material to our financial position, results of operations or cash flows. However, it is not possible to predict or determine the outcomes of the legal actions brought against us or by us, or to provide an estimate of all additional losses, if any, that may arise. At December 31, 2011, we have recorded the estimated amount of potential exposure we may have with respect to litigation and claims. Such amounts are not material to the financial statements.

Item 4. ***Mine Safety Procedures***

Not applicable.

PART II

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

Market Information

Our common stock is privately held and there is no established public trading market for our common stock. As of December 31, 2011, there was one holder of record of our 100 shares of common stock, $0.001 par value.

Dividend Policy

We have not declared or paid any cash dividends on our common stock during our two most recent fiscal years. We do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Covenants within our revolving credit facility and our 9.75% Senior Notes restrict our ability to pay cash dividends on our capital stock. Future declaration and payment of cash dividends, if any, on our common stock will be determined in light of factors deemed relevant by our board of directors, including our earnings, operations, capital requirements and financial condition and restrictions in our financing agreements.

Item 6. ***Selected Consolidated Financial Data (In Thousands)***

As a result of the Merger, which was completed on February 14, 2007, our capital structure and our basis of accounting differ from those prior to the Merger. Our financial data in respect of all reporting periods after February 13, 2007 reflect the Merger under the acquisition method of accounting. The financial information for the periods before the Merger is referred to as Predecessor Period and financial information for the periods after the Merger is referred to as the Successor Period." The adjustments to our assets and liabilities as a result of the Merger have impacted net income subsequent to the Merger. The increase in the basis of the assets has resulted in non-cash charges in periods subsequent to the Merger, principally related to the step-up in the value of our seismic data library and other intangible assets. The book value of our seismic data library was increased by approximately $275.2 million to its then fair market value of $395.6 million. As a result of this step up in value and of our maximum four-year straight-line amortization of seismic data, our data amortization expense has increased in the Successor Period. In addition, we recorded identifiable intangible assets with a fair value of $53.4 million of which $52.5 million is amortizable over their useful lives ranging from 1 to 10 years. As a result of this step up in value, amortization expense of acquired intangible assets has increased in the Successor Period.

The following table summarizes certain historical consolidated financial data of Seitel and is qualified in its entirety by the more detailed consolidated financial statements and notes thereto included herein.

	SUCCESSOR PERIOD					PREDECESSOR PERIOD
	Year Ended December 31,					
	2011	2010	2009	2008	Feb. 14, 2007 - Dec. 31, 2007	Jan. 1, 2007 - Feb. 13, 2007
Statement of Operations Data:						
Revenue	$ 218,008	$ 175,556	$ 115,345	$ 172,403	$ 129,802	$ 19,010
Expenses and costs:						
Depreciation and amortization	142,963	175,592	150,199	168,629	146,072	11,485
Impairment of intangible asset				225		
Cost of sales	100	97	290	462	218	8
Selling, general and administrative	31,649	31,831	25,090	36,316	33,393	3,577
Merger				357	2,657	17,457
	174,712	207,520	175,579	205,989	182,340	32,527
Income (loss) from operations	43,296	(31,964)	(60,234)	(33,586)	(52,538)	(13,517)
Interest expense, net	(34,767)	(40,536)	(40,696)	(40,017)	(38,844)	(2,284)
Foreign currency exchange gains (losses)	(726)	441	1,008	(4,059)	3,173	(102)
Loss on early extinguishment of debt	(7,912)					
Gain on sale of marketable securities	2,467	4,188				
Other income	250	446	151	40	39	12
Income (loss) before income taxes	2,608	(67,425)	(99,771)	(77,622)	(88,170)	(15,891)
Provision (benefit) for income taxes	392	(4,008)	(2,974)	(3,548)	(11,057)	452
Net income (loss)	$ 2,216	$ (63,417)	$ (96,797)	$ (74,074)	$ (77,113)	$ (16,343)

	As of December 31,				
	2011	2010	2009	2008	2007
Balance Sheet Data:					
Cash and cash equivalents	$ 74,894	$ 89,971	$ 26,270	$ 42,678	$ 43,443
Seismic data library, net	120,694	106,104	200,389	279,257	349,039
Total assets	500,330	491,009	522,019	643,825	743,101
Total debt	278,256	405,604	405,732	405,499	406,481
Stockholder s equity (deficit)	109,840	(7,022)	46,361	115,785	220,958
Common shares outstanding	100	100	100	100	100

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

The following discussion should be read in conjunction with our consolidated financial statements and the related notes to the financial statements included elsewhere in this document.

Overview

General

Our products and services are used by oil and gas companies to assist in oil and gas exploration and development and management of hydrocarbon reserves. Prior to the recent shift in activity from conventional to unconventional plays, seismic data had been used for both exploration and production purposes but with a heavy bias towards exploration to increase the probability of drilling success. With this recent shift, customer bias has reversed and seismic data is heavily employed in production, especially in the design of horizontal drilling and fracking programs. We own an extensive library of onshore and offshore seismic data that we offer for license to oil and gas companies. We believe that our library of onshore seismic data is the largest available for licensing in North America. We generate revenue primarily by licensing data from our data library and from new data creation products, which are substantially underwritten or paid for by our clients. By participating in underwritten, nonexclusive surveys or purchasing licenses to existing data, oil and gas companies can obtain access to surveys at reduced costs as compared to acquiring seismic data on a proprietary basis.

Our primary areas of focus are onshore United States and Canada and, to a lesser extent, offshore U.S. Gulf of Mexico. These markets continue to experience major changes. Major integrated oil and gas companies and national oil companies have become more active in the North American market, primarily in the unconventional plays, through joint ventures, asset purchases and corporate transactions. The larger independent oil and gas companies continue to be responsible for a significant portion of current U.S. drilling activity. Our offshore seismic data is primarily located in the shallow waters of the U.S. Gulf of Mexico and generates a small percentage of our revenue.

Our clients continue to seek our services to create data in the United States and Canada. On March 7, 2012, our clients' commitment for underwriting on new data creation projects was $100.9 million. Licensing data off the shelf does not require the longer planning and lead times like new data creation and thus is more likely to fluctuate quarter to quarter.

Principal Factors Affecting Our Business

Our business is dependent upon a variety of factors, many of which are beyond our control. The following are those that we consider to be principal factors affecting our business.

Demand for Seismic Data: Demand for our products and services is cyclical due to the nature of the oil and gas industry. In particular, demand for our seismic data services depends upon exploration, production, development and field management spending by oil and gas companies and, in the case of new data creation, the willingness of these companies to forgo ownership in the seismic data. Capital expenditures by oil and gas companies depend upon several factors, including actual and forecasted oil and natural gas commodity prices, prospect availability and the companies' own short-term and strategic plans. These capital expenditures may also be affected by worldwide economic or industry-wide conditions. With the shift to unconventional plays, seismic data is increasingly tied to relatively stable development capital expenditures.

Merger and Acquisition/Joint Venture Activity: Merger and acquisition activity continues to occur within our client base. This activity could have a negative impact on seismic companies that operate in markets with a limited number of participating clients. However, we believe that, over time, this activity could have a positive impact on our business, as it should generate re-licensing fees, result in increased vitality in the trading of mineral interests and result in the creation of new independent customers through the rationalization of staff within those companies affected by this activity.

Exploiting shale plays is a capital intensive endeavor and many technically proficient E&P companies remain capital constrained. They find themselves needing to sell their positions to, or create partnerships with, large well-capitalized companies in order to develop their recoverable resource base. These joint venture partners or new owners will often need to purchase licenses to our seismic data for their own use.

North America Drilling Activity: With relatively strong oil prices and weak natural gas prices, drilling activity has shifted to areas with liquids-rich hydrocarbons, such as the Eagle Ford, Bakken and Niobrara. There are an increasing number of horizontal rigs drilling in oil- and liquids-rich areas and we believe that activity in these areas will continue to increase while activity in dry gas areas will decrease until demand and gas prices strengthen.

Availability of Capital for Our Customers: Some of our customers are independent oil and gas companies and private prospect-generating companies that rely primarily on private capital markets to fund their exploration, production, development and field management activities. Reductions in cash flows resulting from lower commodity prices, along with the reduced availability of credit and increased costs of borrowing, could have a material impact on the ability of such companies to obtain funding necessary to purchase our seismic data.

Government Regulation: Our operations are subject to a variety of federal, provincial, state, foreign and local laws and regulations, including environmental and health and safety laws. We invest financial and managerial resources to comply with these laws and related permit requirements. Modification of existing laws or regulations and the adoption of new laws or regulations limiting or increasing exploration or production activities by oil and gas companies may have a material effect on our business operations.

Non-GAAP Key Performance Measures

Management considers certain performance measures in evaluating and managing our financial condition and operating performance at various times and from time to time. Some of these performance measures are non-GAAP financial measures. Generally, a non-GAAP financial measure is a numerical measure of a company's performance, financial position or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with United States generally accepted accounting principles, or GAAP. These non-GAAP measures are not in accordance with, nor are they a substitute for, GAAP measures. These non-GAAP measures are intended to supplement our presentation of our financial results that are prepared in accordance with GAAP.

The following are the key performance measures considered by management.

Cash Resales

Cash resales represent new contracts for data licenses from our library, including data currently in progress, payable in cash. We believe this measure is important in gauging new business activity. We expect cash resales to generally follow a consistent trend over several quarters, while considering our normal seasonality. Volatility in this trend over several consecutive quarters could indicate changing market conditions.

The following is a reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure, total revenue (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Cash resales	$ 134,497	$ 137,605	$ 49,268
Other revenue components:			
Acquisition revenue	77,406	40,500	37,403
Non-monetary exchanges	7,609	4,678	1,764
Revenue recognition adjustments	(5,856)	(11,005)	22,386
Solutions and other	4,352	3,778	4,524
Total revenue	$ 218,008	$ 175,556	$ 115,345

Cash EBITDA

Cash EBITDA represents cash generated from licensing data from our seismic library net of recurring cash operating expenses. We believe this measure is helpful in determining the level of cash from operations we have available for debt service and funding of capital expenditures (net of the portion funded or underwritten by our customers). Cash EBITDA includes cash resales plus all other cash revenues other than from data acquisitions, plus gains on sales of marketable securities obtained as part of licensing our seismic data, less cost of goods sold and cash selling, general and administrative expenses (excluding non-recurring corporate expenses such as severance, one-time costs associated with cost reduction measures and debt restructure costs).

The following is a quantitative reconciliation of this non-GAAP financial measure to the most directly comparable GAAP financial measure, operating income (loss) (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Cash EBITDA	$ 112,031	$ 117,252	$ 32,868
Add (subtract) other revenue components not included in cash EBITDA:			
Acquisition revenue	77,406	40,500	37,403
Non-monetary exchanges	7,609	4,678	1,764
Revenue recognition adjustments	(5,856)	(11,005)	22,386
Solutions non-cash revenue	71		
Less:			
Gain on sale of marketable securities	(2,467)	(4,188)	
Depreciation and amortization	(142,963)	(175,592)	(150,199)
Non-recurring corporate expenses	(1,792)	(176)	(1,170)
Non-cash operating expenses	(743)	(3,433)	(3,286)
Operating income (loss)	$ 43,296	$ (31,964)	$ (60,234)

Growth of our Seismic Data Library

We regularly add to our seismic data library through four different methods: (1) recording new data; (2) buying ownership of existing data for cash; (3) obtaining ownership of existing data sets through non-monetary exchanges; and (4) creating new value-added products from existing data within our library. For the years ended December 31, 2011, 2010 and 2009, we completed the addition of approximately 2,200 square miles, 900 square miles and 700 square miles, respectively, of seismic data to our library. For the period from January 1, 2012 to March 7, 2012 we completed the addition of approximately 850 square miles and as of March 7, 2012 we had approximately 2,250 square miles of seismic data in progress.

Critical Accounting Policies

We operate in one business segment, which is made up of seismic data acquisition, seismic data licensing, seismic data processing and seismic reproduction services.

We prepare our financial statements and the accompanying notes in conformity with GAAP, which requires management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition and results of operations and the degree of difficulty, subjectivity and complexity in their deployment. Notes A and B of the notes to the consolidated financial statements include a summary of the significant accounting policies used in the preparation of the accompanying consolidated financial statements. The following is a brief discussion of our most critical accounting policies.

Revenue Recognition

Revenue from Data Acquisition

We generate revenue when we create a new seismic survey that is initially licensed by one or more of our customers to use the resulting data. We consider the contracts signed up to the time we make a firm commitment to create the new seismic survey as underwriting. Underwriting revenue is recognized throughout the creation period using the proportional performance method based upon costs incurred and work performed to date as a percentage of total estimated costs and work required. Management believes that this method is the most reliable and representative measure of progress for our data creation projects. The customers paying for the initial licenses receive legally enforceable rights to any resulting product of the specific activities required to complete the survey. The customers also receive access to and use of the newly acquired, processed data.

Revenue from Non-Exclusive Data Licenses

We recognize a substantial portion of our revenue from licensing of data once it is available for delivery. Revenue from the non-exclusive licensing of seismic data is recognized when the following criteria are met:

- we have an arrangement with the customer that is validated by a signed contract;
- the sales price is fixed and determinable;
- collection is reasonably assured;
- the customer has selected the specific data or the contract has expired without full selection;
- the data is currently available for delivery; and
- the license term has begun.

Copies of the data are available to the customer immediately upon request.

For licenses that have been invoiced for which payment is due or has been received, but have not met the aforementioned criteria, the revenue is deferred along with the related direct costs (primarily sales commissions). This normally occurs under the library card, review and possession or review only license contracts because the data selection may occur over time. Additionally, if the contract allows licensing of data that is not currently available or enhancements, modifications or additions to the data are required per the contract, revenue is deferred until such time that the data is available.

Revenue from Non-Monetary Exchanges

In certain cases, we will take ownership of a customer's seismic data or revenue interest (collectively referred to as data) or receive advanced data processing services in exchange for a non-exclusive license to selected seismic data from our library, as partial consideration for the underwriting of new data acquisition or, in some cases, services provided by Solutions. These exchanges are referred to as non-monetary exchanges. In non-monetary exchange transactions, we record a data library asset for the data received or processed at the time the contract is entered into or the data is completed, as applicable, and recognize revenue on the transaction in equal value in accordance with our policies on revenue from data licenses, which is, when the seismic data is selected by the customer, or revenue from data acquisition, as applicable, or as services are provided by Solutions. These transactions are valued at the fair value of the data received or delivered, whichever is more readily determinable.

Seismic Data Library

Costs associated with creating, acquiring or purchasing seismic data are capitalized and amortized principally on the income forecast method subject to a straight-line amortization period of four years, applied on a quarterly basis at the individual survey level.

Data Library Amortization

We amortize our seismic data library using the greater of the amortization that would result from the application of the income forecast method (subject to a minimum amortization rate) or a straight-line basis over the useful life of the data. Due to the subjectivity inherent in the income forecast amortization method, this amortization policy ensures a minimum level of amortization will be recorded if sales of the specific data do not occur as expected and ensures that costs are fully amortized at the end of the data s useful life. With respect to each survey in the data library, the straight-line policy is applied from the time such survey is available for licensing to customers on a non-exclusive basis.

We apply the income forecast method by forecasting the ultimate revenue expected to be derived from a particular data library component over the estimated useful life of each survey comprising part of such component. We make this forecast annually and review it quarterly. If, during any such review, we determine that the ultimate revenue for a library component is expected to be significantly different than the original estimate of total revenue for such library component, we revise the amortization rate attributable to future revenue from each survey in such component.

The greater of the income forecast or straight-line amortization policy is applied quarterly on a cumulative basis at the individual survey level. Under this policy, we first record amortization using the income forecast method. The cumulative amortization recorded for each survey is then compared with the cumulative straight-line amortization. If the cumulative straight-line amortization is higher for any specific survey, additional amortization expense is recorded, resulting in accumulated amortization being equal to the cumulative straight-line amortization for such survey. This requirement is applied regardless of future-year revenue estimates for the library component of which the survey is a part and does not consider the existence of deferred revenue with respect to the library component or to any survey.

Seismic Data Library Impairment

We evaluate our seismic data library for impairment by grouping individual surveys into components based on our operations and geological and geographical trends. We believe that these library components constitute the lowest levels of independently identifiable cash flows. We evaluate our seismic data library investment for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. We consider the level of sales performance in each component compared to projected sales, as well as industry conditions, among others, to be key factors in determining when our seismic data should be evaluated for impairment. In evaluating sales performance of each component, we generally consider five consecutive quarters of actual performance below forecasted sales to be an indicator of potential impairment.

The impairment evaluation is based first on a comparison of the undiscounted future cash flows over each component's remaining estimated useful life with the carrying value of each library component. If the undiscounted cash flows are equal to or greater than the carrying value of such component, no impairment is recorded. If undiscounted cash flows are less than the carrying value of any component, the forecast of future cash flows related to such component is discounted to fair value and compared with such component's carrying amount. The difference between the library component's carrying amount and the discounted future value of the expected revenue stream is recorded as an impairment charge.

For purposes of evaluating potential impairment losses, we estimate the future cash flows attributable to a library component by evaluating, among other factors, historical and recent revenue trends, oil and gas prospectivity in particular regions, general economic conditions affecting our customer base, expected changes in technology and other factors that we deem relevant. The cash flow estimates exclude expected future revenues attributable to non-monetary data exchanges and future data creation projects.

The estimation of future cash flows and fair value is highly subjective and inherently imprecise. Estimates can change materially from period to period based on many factors, including those described in the preceding paragraph. Accordingly, if conditions change in the future, we may record impairment losses relative to our seismic data library, which could be material to any particular reporting period.

Business Acquisitions and Goodwill

We account for acquired businesses using the acquisition method of accounting which requires that the assets acquired and liabilities assumed be recorded at the date of acquisition at their respective fair values. The cost to acquire a business is allocated to the underlying net assets of the acquired business in proportion to their respective fair values. Any excess of the purchase price over the estimated fair values of the net assets acquired is recorded as goodwill.

Goodwill is not amortized to earnings but is assessed, at least annually, for impairment at the reporting unit level. During 2011, we adopted Accounting Standards Update (ASU) 2011-08 Testing Goodwill for Impairment . ASU 2011-08 permits an entity to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. We conduct a qualitative goodwill impairment assessment as of October 1 of each year by examining relevant events and circumstances which could have a negative impact on our goodwill such as macroeconomic conditions, industry and market conditions, cost factors that have a negative effect on earnings and cash flows, overall financial performance, and other relevant entity-specific events.

If after assessing the totality of events or circumstances described above, we determine that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, the two-step goodwill test is performed. The two-step goodwill impairment test is also performed whenever events or changes in circumstances indicate that the carrying value may not be recoverable.

The two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized. The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of the reporting unit exceeds its carrying amount, goodwill is not considered to be impaired, and the second step of the test is not required. If necessary, the second step of the impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to the excess.

Use of Estimates and Assumptions

In preparing our financial statements, a number of estimates and assumptions are made by management that affect the accounting for and recognition of assets, liabilities, revenues and expenses. These estimates and assumptions must be made because certain information that is used in the preparation of our financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available or is not otherwise capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine and we must exercise significant judgment.

The most difficult, subjective and complex estimates and assumptions that deal with the greatest amount of uncertainty are related to our accounting for our seismic data library and goodwill.

Accounting for our seismic data library requires us to make significant subjective estimates and assumptions relative to future sales and cash flows from such library. These cash flows impact amortization rates, as well as potential impairment charges. Any changes in these estimates or underlying assumptions will impact our income from operations prospectively from the date changes are made. To the extent that such estimates, or the assumptions used to make those estimates, prove to be significantly different than actual results, the carrying value of the seismic data library may be subject to higher prospective amortization rates, additional straight-line amortization or impairment losses.

Because we apply a minimum income forecast amortization rate of 70%, the effect of decreasing future sales by 10%, with all other factors remaining constant, would cause the range of amortization rates to be from 70% to 73% as of January 1, 2012. The effect of decreasing future sales by 20%, with all other factors remaining constant, would cause the range of amortization rates to be from 70% to 82% as of January 1, 2012.

In a portion of our seismic data library activities, we engage in certain non-monetary exchanges and record a data library asset for the seismic data received and recognize revenue on the transaction in accordance with our policies on revenue recognition. These transactions are valued at the fair value of the data received by us or licenses or services granted by us, whichever is more readily determinable. In addition, we obtain third-party concurrence on the portfolio of all non-monetary exchanges for data valued at $750,000 or more in order to support our estimate of the fair value of the transactions. Our estimate of the value of these transactions is highly subjective and based, in large part, on data sales transactions between us and a limited number of customers over a limited time period, and appraisals of the value of such transactions based on a relatively small market of private transactions over a limited period of time.

We conduct a qualitative goodwill impairment assessment at least annually. If, based on our qualitative procedures, it is more likely than not that the fair value of a reporting unit is less than its carrying amount, we are required to perform a two-step impairment test to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized. The impairment test involves a comparison of the fair value of a reporting unit with its carrying amount, including goodwill to identify if a goodwill impairment exists. If necessary, an impairment loss is recognized as an amount equal to the excess of the carrying amount of goodwill over the implied fair value of goodwill. For our estimates of the fair value of goodwill, we prepare discounted cash flow analysis, which requires significant judgments and estimates about our future performance. If these projected cash flows change materially, we may be required to record impairment losses relative to goodwill.

Actual results could differ materially from the estimates and assumptions that we use in the preparation of our financial statements. To the extent management's estimates and assumptions change in the future, the effect on our reported results could be significant to any particular reporting period.

Results of Operations

Revenue

The following table summarizes the components of our revenue for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	$00000000	$00000000	$00000000
		Year Ended December 31,	
	2011	2010	2009
Acquisition revenue:			
Cash underwriting	$ 75,132	$ 37,823	$ 34,565
Underwriting from non-monetary exchanges	2,274	2,677	2,838
Total acquisition revenue	77,406	40,500	37,403
Resale licensing revenue:			
Cash resales	134,497	137,605	49,268
Non-monetary exchanges	7,609	4,678	1,764
Revenue recognition adjustments	(5,856)	(11,005)	22,386
Total resale licensing revenue	136,250	131,278	73,418
Total seismic revenue	213,656	171,778	110,821
Solutions and other	4,352	3,778	4,524
Total revenue	$ 218,008	$ 175,556	$ 115,345

Total revenue was $218.0 million for the year ended December 31, 2011 compared to $175.6 million for the year ended December 31, 2010. This $42.5 million, or 24%, increase was primarily due to an increase in acquisition revenue. Acquisition revenue increased to $77.4 million in 2011 compared to $40.5 million in 2010 due to our campaign to acquire data in unconventional plays and client interest in participating in the new projects. All of our data acquisition revenue in 2011 occurred in the key active unconventional plays in North America, primarily the Eagle Ford in south Texas, Marcellus in Pennsylvania, Niobrara in Colorado and Montney and Cardium in British Columbia. Total resale licensing revenue was $136.3 million in 2011 compared to $131.3 million in 2010. Cash resales were $134.5 million in 2011 compared to $137.6 million in 2010. Cash resales from 3D data located in unconventional plays totaled $105.3 million, or 78%, of our cash resales in 2011 compared to $93.9 million, or 68%, in 2010. Cash resales from conventional 3D, 2D and offshore data totaled $29.2 million and $43.7 million in 2011 and 2010, respectively. Non-monetary exchanges fluctuate year to year depending upon the data available for trade and totaled $7.6 million in 2011 compared to $4.7 million in 2010. Revenue recognition adjustments are non-cash adjustments to revenue and reflect the net amount of (i) revenue deferred as a result of all of the revenue recognition criteria not being met and (ii) the subsequent revenue recognition once the criteria are met. The increase of $5.1 million in revenue recognition adjustments from 2010 to 2011 was primarily due to an increase in recognition of revenue previously deferred as a result of new data acquisition projects being completed and delivered partially offset by an increase in the deferral of new licensing contracts. Solutions and other revenue increased $0.6 million in 2011 compared to 2010 due to the increase in total seismic revenue and the types of products delivered.

Total revenue was $175.6 million for the year ended December 31, 2010 compared to $115.3 million for the year ended December 31, 2009. This $60.2 million, or 52%, increase was primarily due to an increase in total resale licensing revenue. Acquisition revenue increased from $37.4 million in 2009 to $40.5 million in 2010, with the second half of 2010 reflecting resumed acquisition activity in both the U.S. and Canada following reduced activity in 2009 caused by the economic downturn. Acquisition revenue in 2010 related to unconventional plays, primarily the Haynesville in east Texas, Eagle Ford and Niobrara, as well as Montney and Horn River in Canada. Total resale licensing revenue was $131.3 million in 2010 compared to $73.4 million in 2009. The $57.9 million, or 79%, increase in total resale licensing revenue reflected increased activity by our clients resulting from improving industry conditions and an increase in drilling activity in North America. Cash resales were $137.6 million in 2010, up 179%, compared to $49.3 million in 2009. Cash resales attributable to 3D data located in unconventional plays totaled $93.9 million, or 68%, in 2010 compared to $26.0 million, or 53%, in 2009. Cash resales from conventional 3D, 2D and offshore data totaled $43.7 million and $23.3 million in 2010 and 2009, respectively. Non-monetary exchanges fluctuate year to year depending upon the data available for trade and totaled $4.7 million in 2010 compared to $1.8 million in 2009. In 2010, the deferral of new licensing contracts exceeded the amount of revenue recognized from previously deferred contracts primarily as a result of cash resales on data that are still in the acquisition phase requiring deferral since the data products are not yet available for delivery as well as an increase in the value of library card contracts entered into in the period. Solutions and other revenue decreased $0.7 million in 2010 compared to 2009 due to the completion of a data management project in 2009 and due to the mix of seismic revenue and the types of products delivered.

At December 31, 2011, we had a deferred revenue balance of $48.8 million compared to the December 31, 2010 balance of $37.1 million. The deferred revenue balance was related to (i) data licensing contracts on which selection of specific data had not yet occurred, (ii) deferred revenue on data acquisition projects and (iii) contracts in which the data products are not yet available or the revenue recognition criteria has not yet been met. The deferred revenue will be recognized when selection of specific data is made by the customer, upon expiration of the data selection period specified in the data licensing contracts, as work progresses on the data acquisition contracts, as the data products become available or as all of the revenue recognition criteria are met. Deferred revenue will be recognized no later than the following, based on the expiration of the selection period or our estimate of progress on acquisition projects and the availability of data products, although some revenue may be recognized earlier (in thousands):

	$0000000
2012	$ 42,131
2013	6,551
2014 and thereafter	163

Depreciation and Amortization

Depreciation and amortization was comprised of the following (in thousands):

	$00000000	$00000000	$00000000
	Year Ended December 31,		
	2011	2010	2009
Amortization of seismic data:			
Income forecast	$ 102,210	$ 87,617	$ 65,424
Straight-line	32,758	80,190	77,031
Total amortization of seismic data	134,968	167,807	142,455
Depreciation of property and equipment	2,167	2,081	2,256
Amortization of acquired intangibles	5,828	5,704	5,488
Total	$ 142,963	$ 175,592	$ 150,199

Total seismic data library amortization amounted to $135.0 million, $167.8 million and $142.5 million in 2011, 2010 and 2009, respectively. The amount of seismic data library amortization fluctuates based on the level and location of specific seismic surveys licensed (including licensing resulting from new data acquisition) and selected by our customers during any period as well as the amount of straight-line amortization required under our accounting policy. Additionally, the step-up in our data library value resulting from the Merger became fully amortized in the first quarter of 2011 which has resulted in a decrease in the level of straight-line amortization in 2011.

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Seismic data amortization as a percentage of total seismic revenue is summarized as follows:

Components of Amortization	Year Ended December 31, 2011	2010	2009
Income forecast	48%	51%	59%
Straight-line	15%	47%	70%
Total	63%	98%	129%

The percentage of income forecast amortization to total seismic revenue was 48% for the year ended December 31, 2011; 51% for the year ended December 31, 2010; and 59% for the year ended December 31, 2009. In all three years, we had resale revenue recognized which was from data whose costs were fully amortized. In 2011, 50% of resales did not attract amortization, as compared to 36% in 2010 and 24% in 2009. Straight-line amortization represents the expense required under our accounting policy to ensure our data value is fully amortized within four years of when the data becomes available for sale. The $47.4 million decrease in straight-line amortization from 2010 to 2011 was primarily because a significant portion of our data library became fully amortized in the first quarter of 2011 due to such data reaching its four-year life after the Merger. The $3.2 million increase in straight-line amortization from 2009 to 2010 was due to the distribution of revenue among the various seismic surveys, resulting in more straight-line amortization in 2010.

For both of the years ended December 31, 2011 and 2010, the rates utilized under the income forecast method was 70% for all components. For the year ended December 31, 2009, the amortization rates utilized under the income forecast method ranged from 70% to 74%. The rate of amortization with respect to each component is decreased or increased if our estimate of future cash sales from such component is materially increased or decreased, subject to a minimum amortization rate of 70%. Additionally, certain seismic surveys have been fully amortized; consequently, no amortization expense is required on revenue recorded for these seismic surveys. As of January 1, 2012, the amortization rate to be utilized under the income forecast method is 70% for all components.

In connection with the Merger, we recorded acquired intangible assets of $53.4 million, of which $52.5 million are amortizable over their useful lives ranging from 1 to 10 years. Amortization related to customer relationships and internally developed software totaled $5.8 million, $5.7 million, and $5.5 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Selling, General and Administrative Expenses

Selling, general and administrative (SG&A) expenses were $31.6 million in 2011, $31.8 million in 2010 and $25.1 million in 2009. SG&A expenses are made up of the following expense categories (in thousands):

	$00000000	$00000000	$00000000
	Year Ended December 31, 2011	2010	2009
Cash SG&A expenses	$ 30,906	$ 28,398	$ 21,804
Non-cash equity compensation expense	453	3,157	3,034
Non-cash rent expense	290	276	252
Total	$ 31,649	$ 31,831	$ 25,090

The increase in cash SG&A expenses of $2.5 million from the year ended December 31, 2010 to the year ended December 31, 2011 was primarily due to (1) an increase of $1.4 million in salaries and benefits, (2) an increase of $1.6 million in non-recurring expenses, mainly professional fees incurred with respect to evaluating debt restructuring alternatives and severance costs and (3) an increase of $1.0 million in various other expenses associated with our increased revenue and acquisition activities in 2011. These increases were partially offset by a $1.5 million decrease in our bad debt expense.

The increase in cash SG&A expenses of $6.6 million from the year ended December 31, 2009 to the year ended December 31, 2010 was primarily due to (1) an increase in performance incentive compensation of $4.4 million resulting from the improvement in 2010 cash EBITDA, (2) $0.8 million expense related to a long-term incentive compensation plan implemented in 2010, (3) an increase of $0.9 million in sales commissions as a result of higher revenues and (4) an increase of $1.0 million in our allowance for doubtful accounts. These increases were partially offset by a decrease of $0.5 million in various other expenses primarily related to severance and one-time costs associated with cost reduction measures.

The decrease in non-cash equity compensation expense of $2.7 million between 2010 and 2011 was primarily due to the 2010 period including expense associated with the re-pricing of outstanding options granted to certain employees and non-employee directors. Additionally, there was a reduction in the expense related to stock options due to the expense being recognized using graded vesting and a significant portion of our options becoming fully vested in the first quarter of 2011. Non-cash equity compensation expense increased $0.1 million in 2010 compared to 2009. The re-pricing of our outstanding stock options in May 2010 caused non-cash compensation expense to increase in 2010; this was partially offset by a reduction in expense related to stock options due to the use of graded vesting to amortize the compensation expense.

The non-cash rent expense represents amortization of a favorable facility lease that was recorded as an intangible asset in connection with the Merger and is being amortized over its remaining lease term from the Merger date of 6.25 years.

Other Income (Expense)

Interest expense was $35.2 million for the year ended December 31, 2011, $41.1 million for the year ended December 31, 2010 and $41.2 million for the year ended December 31, 2009. The decrease in interest expense in 2011 was due to the repayment of $125.0 million of our 9.75% Senior Notes on July 1, 2011.

The call premium paid to repay $125.0 million of our 9.75% Senior Notes along with the write-off of the related unamortized issuance costs resulted in a $7.9 million loss on early extinguishment of debt in 2011.

During the years ended December 31, 2011 and 2010, we sold $2.5 million and $4.2 million, respectively, of marketable securities through multiple transactions on an active international exchange. Total gains were equal to the proceeds received.

During the years ended December 31, 2011, 2010 and 2009, we reported foreign currency transaction gains (losses) on U.S. denominated transactions of our Canadian subsidiaries totaling $(0.7) million, $0.4 million and $1.0 million, respectively.

Income Taxes

Tax expense (benefit) was $0.4 million, $(4.0) million and $(3.0) million for the years ended December 31, 2011, 2010 and 2009, respectively. The 2011 expense was comprised of (i) an expense of $1.0 million related to our Canadian operations, (ii) a benefit of $0.4 million related to certain research and development tax credits received in Canada, (iii) a benefit of $0.4 million related to U.S. state taxes and (iv) an expense of $0.2 million related to interest on uncertain tax positions. The Federal tax benefit of $0.2 million in 2011 resulting from our U.S. operations was offset by a valuation allowance because it was more likely than not that the deferred tax asset would not be realized.

The 2010 benefit was comprised of (i) a benefit of $3.7 million related to our Canadian operations, (ii) a benefit of $0.4 million related to certain research and development tax credits received in Canada and (iii) an expense of $0.1 million related to principal, penalties and interest on uncertain tax positions. The Federal tax benefit of $18.1 million in 2010 resulting from our U.S. operations was offset by a valuation allowance because it was more likely than not that the deferred tax asset would not be realized.

The 2009 benefit was comprised of (i) a benefit of $2.8 million related to our Canadian operations, (ii) a benefit of $0.3 million related to certain research and development tax credits received in Canada, (iii) $0.1 million of state tax benefit in the U.S. and (iv) an expense of $0.2 million related to principal, penalties and interest on uncertain tax positions. The Federal tax benefit of $30.8 million in 2009 resulting from our U.S. operations was offset by a valuation allowance because it was more likely than not that the deferred tax asset would not be realized.

Liquidity and Capital Resources

As of December 31, 2011, we had $74.9 million in consolidated cash and cash equivalents, including $245,000 of restricted cash. As of December 31, 2011, approximately $13.2 million of our cash was held by a foreign subsidiary which will be used to reinvest in our Canadian operations as our intent is to use this cash to, among other things, fund the operations of our Canadian subsidiary. If we decide at a later date to repatriate those funds to the U.S., we may be required to provide taxes on certain of those funds based on applicable U.S. tax rates net of foreign taxes.

In addition to the cash on our balance sheet, other sources of liquidity include our credit facility described below.

We maintain sufficient working capital to enable us to meet our obligations for new data acquisition projects. Our working capital practices are consistent with the general practices associated in the industry in which we operate.

Credit Facility: On May 25, 2011, we entered into a credit agreement (Credit Facility) which provides us with the ability to borrow up to $30.0 million. The Credit Facility provides a $30.0 million revolving credit facility with a Canadian sublimit of $5.0 million, subject to borrowing base limitations. The Credit Facility expires on November 15, 2013, which date will be extended upon the occurrence of certain refinancing of our existing 9.75% Senior Notes. The Credit Facility requires that we maintain certain minimum excess availability levels (as defined in the Credit Facility) or the fixed charge coverage ratio (as defined in the Credit Facility) shall not be less than 1.00 to 1.00. As of December 31, 2011, no amounts were outstanding under the Credit Facility and there was $30.0 million of availability.

9.75% Senior Unsecured Notes: On February 14, 2007, we issued in a private placement $400.0 million aggregate principal amount of our 9.75% Senior Notes. The proceeds from the notes were used to partially fund the transactions in connection with the Merger. On July 1, 2011, we redeemed $125.0 million aggregate principal amount of the 9.75% Senior Notes outstanding. The redemption price was equal to 104.875% of the principal amount of the notes, plus accrued and unpaid interest. Interest on these senior notes is payable in cash, semi-annually in arrears on February 15 and August 15. As of December 31, 2011, $275.0 million of the 9.75% Senior Notes remain outstanding.

We may from time to time, as part of various financing and investing strategies, purchase our outstanding indebtedness. These purchases, if any, could have a material positive or negative impact on our liquidity available to repay outstanding debt obligations or on our consolidated results of operations.

Contractual Obligations: As of December 31, 2011, we had outstanding debt and lease obligations, with aggregate contractual cash obligations, including principal and interest, summarized as follows (in thousands):

	$00000000	$00000000	$00000000	$00000000	$00000000
			Payments due by period		
Contractual cash obligations	Total	2012	2013-2015	2016-2017	2018 and thereafter
Debt obligations [1][2]	$ 342,133	$ 26,884	$ 315,249	$	$
Capital lease obligations [2]	4,359	390	1,209	833	1,927
Operating lease obligations	3,439	1,201	1,714	524	
Total contractual cash obligations	$ 349,931	$ 28,475	$ 318,172	$ 1,357	$ 1,927

(1) Debt obligations include the face amount of our 9.75% Senior Notes totaling $275.0 million.
(2) Amounts include interest related to debt and capital lease obligations.

Cash Flows from Operating Activities*:* Cash flows provided by operating activities were $126.1 million, $109.3 million, and $40.9 million for the years ended December 31, 2011, 2010 and 2009, respectively. Operating cash flows for 2011 increased from 2010 primarily due to increased collections on acquisition underwriting partially offset by lower collections on cash resales and tax payments made to appeal the results of the CRA audit of Olympic Seismic Ltd., a wholly owned subsidiary. Operating cash flows for 2010 increased from 2009 primarily due to the higher level of our cash resales in 2010 and the related cash collections.

Cash Flows from Investing Activities: Cash flows used in investing activities were $127.2 million, $45.7 million, and $56.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. Cash expenditures for seismic data were $127.0 million, $49.5 million, and $55.9 million for the years ended December 31, 2011, 2010 and 2009, respectively. The increase in cash invested in seismic data for 2011 compared to 2010 was due to increased data acquisition activity in both the U.S. and Canada. The decrease in cash invested in seismic data for 2010 compared to 2009 was primarily due to the reduced activity in 2009 caused by the economic downturn which had a continuing effect into 2010.

Cash Flows from Financing Activities: Cash flows used in financing activities were $14.7 million, $0.3 million and $0.2 million for the years ended December 31, 2011, 2010 and 2009, respectively. In 2011, our financing activities primarily consisted of the following: (i) a $125.0 million cash capital contribution by Holdings in connection with the minority interest investment in Holdings by Centerbridge in May 2011, (ii) $131.1 million in principal and premium payments on our 9.75% Senior Notes, (iii) $6.3 million in costs paid in conjunction with our Credit Facility and the Centerbridge transaction and (iv) $2.0 million in principal payments on our 11.75% Senior Notes.

Anticipated Liquidity: Our ability to cover our operating and capital expenses, make required debt service payments on our 9.75% Senior Notes, incur additional indebtedness, and comply with our various debt covenants, will depend primarily on our ability to generate substantial operating cash flows. Over the next 12 months, we expect to obtain the funds necessary to pay our operating, capital and other expenses as well as interest on our 9.75% Senior Notes and principal and interest on our other indebtedness, from our operating cash flows, cash and cash equivalents on hand and, if required, from additional borrowings (to the extent available under our Credit Facility subject to the borrowing base). Our ability to satisfy our payment obligations depends substantially on our future operating and financial performance, which necessarily will be affected by, and subject to, industry, market, economic and other factors. If necessary, we could choose to reduce our spending on capital projects and operating expenses to ensure we operate within the cash flow generated from our operations. We will not be able to predict or control many of these factors, such as economic conditions in the markets where we operate and competitive pressures.

For a discussion of a number of factors that may impact our liquidity and the sufficiency of our capital resources, see Overview and Item 1A. Risk Factors above.

Deferred Taxes

As of December 31, 2011, we had a net deferred tax liability of $1.4 million attributable to our Canadian operations. In the United States, we had a Federal deferred tax asset of $108.0 million, all of which was fully offset by a valuation allowance. The recognition of the U.S. Federal deferred tax asset will not occur until such time that it is more likely than not that some portion or all of the Federal deferred tax asset will be realized. As of December 31, 2011, it was more likely than not that all of the U.S. Federal deferred tax asset will not be realized. Additionally, in the United States, we had a state deferred tax asset of $56,000 which was recognized as it is more likely than not that the state deferred tax asset will be realized.

Off-Balance Sheet Transactions

Other than operating leases, we do not maintain any off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenue or expense, results of operations, liquidity, capital expenditures or capital resources.

Capital Expenditures

During 2011, capital expenditures for seismic data and other property and equipment amounted to $153.0 million. Our capital expenditures for 2012 are presently estimated to be $215.0 million. Our 2011 actual and 2012 estimated capital expenditures are comprised of the following (in thousands):

	Year Ended December 31, 2011	Estimate For Year Ending December 31, 2012