UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 20-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR (g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

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

For the fiscal year ended December 31, 2005

OR

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

For the transition period from to

OR

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

Date of event requiring this shell company report

Commission File Number: 1-14614

Petroleum Geo-Services ASA

(Exact name of registrant as specified in its charter)

Kingdom of Norway

(Jurisdiction of incorporation or organization)

Strandveien 4, N-1325 Lysaker, Norway

(Address of principal executive offices)

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

Title of Each Class	Name of Each Exchange on Which Registered
American Depositary Shares, each representing one ordinary share of nominal value NOK 10 per share	New York Stock Exchange, Inc.
Ordinary shares of nominal value NOK 10 per share*	New York Stock Exchange, Inc.

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

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 60,000,000 ordinary shares, nominal value NOK 10 per share.

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

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☑

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 ☑ No ☐

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark which financial statement the registrant has elected to follow. Item 17 ☐ Item 18 ☑

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ☑ No ☐

* The ordinary shares were registered for technical purposes only, not involving trading privileges, in accordance with the requirements of the Securities and Exchange Commission.

PETROLEUM GEO-SERVICES ASA

ANNUAL REPORT ON FORM 20-F FOR THE YEAR ENDED DECEMBER 31, 2005

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PETROLEUM GEO-SERVICES ASA

As used in this annual report, we refer to Petroleum Geo-Services ASA, its predecessors and its majority-owned subsidiaries as "PGS," "we," "us" or "our," unless the context clearly indicates otherwise.

WHERE YOU CAN FIND MORE INFORMATION

We have filed this annual report on Form 20-F with the Securities and Exchange Commission under the Securities Exchange Act of 1934. Statements made in this annual report as to the contents of any agreement or other document referred to are not necessarily complete. For each such agreement or other document filed as an exhibit to this annual report, we urge you to refer to the exhibit for a more complete description of the matter involved. We are subject to the informational requirements of the Exchange Act that apply to foreign private issuers and file or furnish reports and other information with the SEC. Reports and other information we file with or furnish to the SEC, including this annual report, may be inspected and copied at the public reference facilities of the SEC at 450 Fifth Street N.W., Washington D.C. 20549. Additionally, information that we file electronically with the SEC may also be obtained from its Internet site at *http://www.sec.gov* and our Internet site at *http://www.pgs.com.* Information contained on or connected to our website is not incorporated by reference into this annual report on Form 20-F and should not be considered part of this report or any other filing that we make with the SEC.

FORWARD-LOOKING STATEMENTS

In order to utilize the "Safe Harbor" provisions of the United States Private Securities Litigation Reform Act of 1995, we are providing the following cautionary statement. This annual report, particularly in "Our Business Priorities," "Our Geophysical Services" and "Our Production Segment" in Item 4 and "Outlook; Factors Affecting Our Future Operating Results" and "Liquidity and Capital Resources" in Item 5, contains forward-looking statements about our financial condition, results of operations, businesses and prospects. These forward-looking statements address matters such as:

- market conditions, anticipated demand and prices for our services and for multi-client data that we license, productive capacity in the markets in which we operate, other competitive factors, possible expansion, technological developments and other trends in the businesses in which we operate;
- business strategies, including geographic areas in which we may operate from time to time and potential acquisitions and/or dispositions;
- maintaining and obtaining contracts for our floating production, storage and offloading vessels, the estimated productive lives of the fields served by such vessels and the periods we expect such vessels to continue to produce such fields;
- operating regularity and levels of production for our floating production, storage and offloading vessels;
- the extent to which our seismic vessels and equipment will be utilized, including utilization of such vessels to acquire contract or multi-client seismic data;
- acquisition of contract and multi-client seismic data, governmental licensing activity relating to such acquisition and expected future sales of multi-client seismic data;
- future capital expenditures, investments in our businesses and dividends;
- investments in, and amortization charges for, our multi-client library;
- governmental and tax regulations and enforcement;
- future exposure to currency devaluations or exchange rate fluctuations, including in particular fluctuations in the value of the U.S. dollar as compared to the Norwegian kroner and the British pound; and
- interest rates.

These forward-looking statements:

- address activities, events or developments that we expect, believe, anticipate or estimate will or may occur in the future;
- are based at least in part on assumptions and analyses that we have made and that we believe were reasonable under the circumstances when made; and
- can be impacted by uncertainties and other factors, many of which are beyond our control.

Any one of these assumptions, uncertainties or other factors, or a combination of these assumptions, uncertainties or other factors, could materially affect our future results of operations, financial position, cash flows and whether the forward-looking statements ultimately prove to be accurate. These forward-looking statements are not guarantees of our future performance, and our actual results, financial position, cash flows and future developments may differ materially from those projected in the forward-looking statements. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements disclosed elsewhere in this annual report, including those described under "Key Information — Risk Factors" in Item 3.

CURRENCY PRESENTATIONS

In this annual report, references to "U.S. dollars," "dollars" and "$" are to United States dollars; references to "NOK" are to Norwegian kroner; and references to "British pounds" and "£" are to British pounds sterling.

PART I

ITEM 1. ***Identity of Directors, Senior Management and Advisors***

Not applicable.

ITEM 2. ***Offer Statistics and Expected Timetable***

Not applicable.

ITEM 3. ***Key Information***

Selected Financial Data

We have presented below, on the basis of U.S. generally accepted accounting principles ("U.S. GAAP"), our selected consolidated financial data as of December 31, 2005, 2004 and 2003 (Successor Company) and as of December 31, 2002 and 2001 (Predecessor Company), for the years ended December 31, 2005 and 2004 and for the two-month period ended December 31, 2003 (Successor Company) and for the ten-month period ended October 31, 2003 and the years ended December 31, 2002 and 2001 (Predecessor Company). We have derived the financial data presented below from our audited financial statements including those included in Item 18 of this annual report. The financial data presented below excludes our Production Services subsidiary, our Atlantis oil and natural gas subsidiary and PGS Tigress (UK) Ltd., our software subsidiary, which were sold in 2002 and 2003 and are presented as discontinued operations in our financial statements for all periods. You should read the financial data in conjunction with "Operating and Financial Review and Prospects" in Item 5 of this annual report and our consolidated financial statements and related notes included in Item 18 of this annual report. The financial data presented below are qualified in their entirety by reference to those consolidated financial statements and related notes.

We operated our business as a debtor-in-possession under Chapter 11 of the U.S. Bankruptcy Code from July 29, 2003 until November 5, 2003, when our reorganization plan became effective and was substantially consummated. Under the plan, our then-existing bank debt and outstanding senior notes were cancelled in exchange for a combination of new senior notes, a new term loan, new ordinary shares and the right to receive cash. For additional information about our Chapter 11 reorganization, please read "Operating and Financial Review and Prospects — 2003 Financial Restructuring" in Item 5 of this annual report and note 3 of the consolidated financial statements included in Item 18 of this annual report.

We have prepared our post-reorganization consolidated financial statements in accordance with the American Institute of Certified Public Accountants Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code,"* or SOP 90-7. For financial reporting purposes, the effects of the completion of the reorganization plan and adjustments for fresh-start reporting have been recorded as of October 31, 2003. Under fresh-start reporting, a new entity was deemed created for financial reporting purposes, and the carrying values of our assets were adjusted to their reorganization values, which are equivalent to their estimated fair values. The carrying values of our liabilities were also adjusted to their present values. The terms "Predecessor" and "Predecessor Company" refer to PGS and its subsidiaries for periods prior to and including October 31, 2003. The terms "Successor" and "Successor Company" refer to PGS and its subsidiaries for periods from and after November 1, 2003. The effects of the completion of the reorganization plan and adjustments for fresh-start reporting recorded as of October 31, 2003 are Predecessor

Company transactions. All other results of operations on November 1, 2003 are Successor Company transactions.

	Successor Company			Predecessor Company		
	Years Ended December,		Two Months Ended December 31,	Ten Months Ended October 31,	Years Ended December,	
	2005	2004	2003	2003	2002	2001
	(In thousands of dollars, except for share data)					
STATEMENT OF OPERATIONS DATA:						
Revenues	$1,196,326	$1,129,468	$ 172,371	$ 961,864	$ 1,043,231	$ 893,230
Operating profit (loss)	335,447	35,683	10,702	9,825	(488,609)	46,798
Debt redemption and refinancing costs	(107,315)	—	—	—	—	—
Reorganization items:						
Gain on debt discharge	—	—	—	1,253,851	—	—
Fresh-start adoption	—	—	—	(532,268)	—	—
Cost of reorganization	—	(3,498)	(3,325)	(52,334)	(3,616)	—
Income (loss) from continuing operations before cumulative effect of change in accounting principles	112,078	(137,778)	(9,818)	556,938	(809,903)	(140,125)
Net income (loss)	112,578	(134,730)	(9,953)	557,045	(1,174,678)	(172,479)
Basic and diluted income (loss) from continuing operations per share	$ 1.87	$ (2.30)	$ (0.17)	$ 5.39	$ (7.84)	$ (1.36)
Basic and diluted net income (loss) per share	1,88	(2.25)	(0.17)	5.39	(11.37)	(1.68)
Basic and diluted weighted average shares outstanding(a)	60,000,000	60,000,000	60,000,000	103,345,987	103,345,987	102,768,283
CASH FLOW DATA:						
Cash flows provided by operating activities	$ 279,056	$ 282,372	$ 62,170	$ 164,948	$ 294,609	$ 110,581
Cash flows provided by (used in) investing activities	10,499	(183,446)	(25,089)	(69,732)	(274,497)	(220,516)
Cash flows provided by (used in) financing activities	(300,953)	(71,283)	(25,807)	(92,896)	(7,636)	64,349
Capital expenditures	90,490	148,372	15,985	42,065	56,735	147,536
Investment in multi-client library	55,667	41,140	9,461	81,142	151,590	174,028

(a) At our Annual General Meeting on June 8, 2005, our shareholders approved a three-for-one split of our shares. Following the split, and as of December 31, 2005, we had 60,000,000 shares issued and outstanding, all of which are of the same class and have equal voting and dividend rights. Each share has a par value of NOK 10. All Successor Company share and per-share information included in this annual report gives effect to this three-for-one split of our shares.

	Successor Company			Predecessor Company	
	December 31,			December 31,	
	2005	2004	2003	2002	2001
	(In thousands of dollars)				
BALANCE SHEET DATA:					
Total assets	$1,717,572	$1,852,153	$1,997,360	$2,839,757	$3,962,129
Multi-client library, net	146,171	244,689	408,005	583,859	799,062
Total long-term debt and capital lease obligations	935,339	1,118,346	1,172,147	1,409,134	1,964,888
Guaranteed preferred beneficial interest in PGS junior subordinated debt securities	—	—	—	142,322	141,000
Common stock	85,714	85,714	85,714	71,089	71,089
Shareholders' equity (deficit)	329,275	222,907	353,634	(192,254)	979,896

Risk Factors

You should carefully consider the risks described below. If any of the following risks actually occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our securities could decline significantly.

Risk Factors Relating to Financial Reporting Matters

We still have issues regarding our internal control over financial reporting. Failure to achieve and maintain effective internal controls could adversely affect both our ability to provide timely and accurate financial statements and the trading prices of our securities.

In September 2003, our independent registered public accounting firm, Ernst & Young AS ("EY"), identified material weaknesses regarding various elements of our system of internal controls over financial reporting. A material weakness condition exists when significant control deficiencies, or a combination of control deficiencies, are present that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. In May 2005, in connection with the audit of our 2004 financial statements under U.S. GAAP, EY confirmed the continuation of such matters that, in the aggregate, they considered to constitute a material weakness.

We believe that the actions we have taken to date to improve our internal controls have remediated the previously identified material weaknesses. However, our assessment of our internal controls for the period relevant to the 2005 financial reporting indicated that two significant control deficiencies remained as of December 31, 2005 regarding the sufficiency of our supervisory review procedures related to income tax provision and regarding timely and sufficiently detailed research and documentation of certain significant accounting issues. A significant deficiency exists when the timeliness and quality control procedures allow more than a remote likelihood that a misstatement of our annual financial statements that is more than inconsequential may not be prevented or detected. Our assessment also identified other control deficiencies.

Beginning with the year ending December 31, 2006, Section 404 of the Sarbanes-Oxley Act will require us to include an internal control report of management with our annual report on Form 20-F. We expect to continue to make changes in our internal control over financial reporting during our documentation and control evaluation in preparation for compliance with Section 404 of the Sarbanes-Oxley Act. As we implement remaining changes in our internal controls and as we address requirements under the Sarbanes-Oxley Act, we may identify additional deficiencies in our system of internal control over financial reporting that will require additional remedial efforts.

If we do not maintain effective internal control over financial reporting, we may be unable to process key components of our results of operations and financial condition timely and accurately, investors and rating agencies could lose confidence in our reported financial information and the trading prices of our securities could be adversely affected.

Our adoption of "fresh start" reporting may make future financial statements difficult to compare.

In connection with the November 2003 consummation of our reorganization plan, we adopted, as of November 1, 2003, fresh start reporting in accordance with SOP 90-7. Because SOP 90-7 required us to reset our assets and liabilities to then current fair values, our financial condition and results of operations after our reorganization are not comparable to the financial condition and results of operations reflected in our historical financial statements for periods prior to November 2003. This may make it difficult to assess our performance after the reorganization compared with our historical performance prior to the reorganization.

Risk Factors Relating to Our Indebtedness and Other Obligations

We have significant indebtedness and other obligations that restrict us in various ways.

We have a relatively high level of indebtedness in relation to our capital structure. As of December 31, 2005, we had approximately $980 million of indebtedness and capital leases outstanding. Our credit facility and other debt and contractual obligations contain covenants and restrictions, including provisions that could restrict our ability, among other things, to sell assets; incur additional indebtedness or issue preferred stock; prepay interest and principal on our indebtedness (other than our main credit agreement); pay dividends and distributions or repurchase our capital stock; create liens on assets; make investments, loans, guarantees or advances; make acquisitions; engage in mergers or consolidations; enter into sale and leaseback transactions; engage in transactions with affiliates; amend material agreements governing our indebtedness; change our business; enter into agreements that restrict dividends from subsidiaries; and enter into speculative financial derivative agreements. In addition, our credit facility requires us to comply with specific financial covenants, including a maximum total leverage ratio, a minimum interest coverage ratio and a minimum fixed charge coverage ratio. Because of this debt and other contractual obligations:

- we must dedicate some portion of our cash flow from operations to debt service and other contractual obligations, which reduces the amount we have available for capital investment, working capital or other general corporate purposes;
- we are more vulnerable to adverse developments in general economic and industry conditions;
- we may be less flexible in responding to changing market conditions or in pursuing favorable business opportunities;
- we may be limited in our ability to borrow additional funds; and
- we may be at a competitive disadvantage compared to our competitors that have less debt.

Our ability to obtain additional financing or to refinance our indebtedness could be restricted.

As of March 2006, our long-term secured indebtedness carried a non-investment grade rating from both Moody's Investors Service, Inc. rating agency (Ba3) and Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc. (B+). As long as we have a non-investment grade credit rating, our access to the debt capital markets will be restricted to the non-investment grade sector. Such a situation could increase our borrowing costs or restrict our ability to obtain additional financing or to refinance our existing indebtedness, or to do so on satisfactory terms.

Risk Factors Relating to Our Business Operations Generally

We have experienced substantial losses in the past and may do so in the future.

For the year ended December 31, 2004, we suffered a net loss of $135 million. We may incur net losses, as well as operating losses, in the future.

Our business could be adversely affected if demand for our services from oil and natural gas companies decreases.

Our geophysical and offshore production businesses depend substantially upon exploration, development and production spending by oil and natural gas companies. Capital expenditures, and in particular exploration and development expenditures, by oil and natural gas companies have tended in the past to follow the prices of oil and natural gas, which have fluctuated widely in recent years. Lower oil and natural gas prices, actual or projected, and other factors, including mergers of oil and natural gas companies, may reduce the level of those expenditures, which could adversely affect our businesses.

We could incur operating losses if we cannot keep our vessels and other equipment utilized at high levels.

Our businesses are capital intensive, and we make significant investments in vessels and in processing, seismic and other equipment. We also incur relatively high fixed costs in our operations. As a result, if we cannot keep our vessels and other equipment utilized at relatively high levels, due to reduced demand, weather interruptions, equipment failure, technical difficulties, labor unrest or other causes, we could incur significant operating losses.

Our future revenues may fluctuate significantly from period to period.

Our future revenues may fluctuate significantly from quarter to quarter and from year to year as a result of various factors including the following:

- fluctuating oil and natural gas prices, which may impact customer demand for our services;
- different levels of activity planned by our customers;
- the timing of offshore lease sales and licensing rounds and the effect of such timing on the demand for seismic data and geophysical services;
- the timing of award and commencement of significant contracts for offshore production services and geophysical data acquisition services;
- weather and other seasonal factors; and
- seasonality in the sales of geophysical data from our multi-client data library.

Our technology could be rendered obsolete since technological changes and new products and services are regularly introduced to our markets, and we may not be able to develop and produce competitive products and services on a cost-effective and timely basis.

We will be required to invest substantial capital to maintain competitive technologies. Technology changes rapidly, and new and enhanced products and services are frequently introduced in our markets, particularly in the geophysical services and seismic data processing business. Our success depends to a significant extent on our ability to develop and produce new and enhanced products and services on a cost-effective and timely basis in accordance with industry demands. While we commit resources to research and development, we may encounter resource constraints or technical or other difficulties that could delay introduction of new and enhanced products and services in the future. In addition, continuing development of new products and services inherently carries the risk of obsolescence of older products and services. New and enhanced products and services, if introduced, may not gain market acceptance or may be adversely affected by technological changes.

Unpredictable changes in governmental regulations could increase our operating costs and reduce demand for our services.

Our operations are affected by a variety of laws and regulations, including those relating to:

- permit or license requirements for geophysical activities and for oil and natural gas exploration, development and production activities;
- exports and imports;
- taxes;
- occupational health and safety; and
- the protection of the environment.

We and our customers are required to invest financial and managerial resources to comply with these laws and regulations. Because these laws and regulations and our business change from time to time, we cannot predict the future costs of complying with these laws and regulations, and our expenditures could increase materially in the future. Modification of existing laws or regulations or adoption of new laws or regulations limiting exploration or production activities by oil and natural gas companies or imposing more stringent restrictions on geophysical or hydrocarbon production-related operations could adversely affect us by increasing our operating costs and/or reducing the demand for our services.

Because we conduct a substantial amount of international operations, we have exposure to those risks inherent in doing business abroad.

A significant portion of our revenue is derived from operations outside the United States and Norway. These operations are subject in varying degrees to risks inherent in doing business abroad, including risks of war, terrorist activities, political, civil or labor disturbances, border disputes and embargoes. Our operations are also subject to various risks related to government activities, including:

- the disruption of operations from labor and political disturbances;
- the possibility of unfavorable changes in tax or other laws;
- partial or total expropriation;
- restrictions on currency repatriation or the imposition of new laws or regulations that preclude or restrict the conversion and free flow of currencies;
- the imposition of new laws or regulations that have the effect of restricting operations or increasing the cost of operations; and
- the disruption or delay of licensing or leasing activities.

We are subject to hazards relating to our geophysical and production businesses.

Our seismic data acquisition and offshore production services often take place under extreme weather and other hazardous conditions. In particular, a substantial portion of our operations are subject to perils that are customary for marine operations, including capsizing, grounding, collision, interruption and damage or loss from severe weather conditions, fire, explosions and environmental contamination from spillage. Any of these risks, whether in our marine or onshore operations, could result in damage to or destruction of vessels or equipment, personal injury and property damage, suspension of operations or environmental damage. In addition, our operations involve risks of a technical and operational nature due to the complex systems that we utilize. If any of these events occur, our business could be interrupted and we could incur significant liabilities. In addition, many similar risks may result in curtailment or cancellation of, or delays in, exploration and production activities of our customers, which could in turn adversely impact our operations.

Because we do not have insurance with third party carriers to cover some operating risks, our results of operations could be adversely affected if one or more of those risks occurred.

We do not carry full insurance for all of our operating risks. Although we generally attempt to carry insurance against the destruction of or damage to our seismic and floating production, storage and offloading vessels and equipment in amounts that we consider adequate, such insurance coverage is subject to various exclusions. In addition, we may not be able to maintain adequate insurance for our vessels and equipment in the future or do so at rates that we consider reasonable. We do not maintain insurance to protect against loss of revenues caused by business interruptions, except for limited protection with respect to the FPSOs *Petrojarl Foinaven* and *Petrojarl Varg.*

Because we generate revenue and incur expenses in various currencies, exchange rate fluctuations and devaluations could have a material impact on our results of operations.

Currency exchange rate fluctuations and currency devaluations could have a material impact on our results of operations from time to time. Historically, most of our revenue and operating expenses have been generated in U.S. dollars, NOK and British pounds, but we predominantly sell our products and services in U.S. dollars while some portion of our operating expenses are incurred in NOK and British pounds. A depreciation in the U.S. dollar compared to these other currencies adversely affects our reported results of operations since expenses denominated in NOK or British pounds are converted into U.S. dollars, our reporting currency, at an increased value. Although we periodically undertake limited hedging activities in an attempt to reduce some currency fluctuation risks, these activities do not provide complete protection from currency-related losses. In addition, in some circumstances our hedging activities can require us to make cash outlays. Finally, the amount of currency hedging transactions we are able to enter into may be limited because of our having a non-investment grade credit rating.

We are subject to intense competition that could limit our ability to maintain or increase our market share and to maintain our prices at profitable levels.

Most of our geophysical and offshore production contracts are obtained through a competitive bidding process. While no single company competes with us in all of our business segments, we are subject to intense competition from large, international companies and smaller, local companies in each of our businesses. Some of our competitors may have greater financial and other resources than us and may be better positioned to withstand and adjust more quickly to volatile market conditions and changes in government regulations. We also face competition from new low-cost competitors in various geographic areas, particularly in the onshore seismic market.

Our strategy of pursuing selective growth opportunities may be unsuccessful if we incorrectly predict operating results for acquired assets or businesses, are unable to identify and complete future acquisitions and integrate acquired assets or businesses or are unable to raise financing for acquisitions on acceptable terms.

The acquisition of assets or businesses on a selective basis or the making of strategic investments on a selective basis in companies or ventures that are complementary to our business is a component of our business strategy. We believe that attractive acquisition and strategic investment opportunities may arise from time to time, and any such acquisition or investment could be significant. At any given time, discussions with one or more potential sellers or possible business partners may be at different stages. However, any such discussions may not result in the consummation of an acquisition transaction or strategic investment, and we may not be able to identify or complete any acquisitions or investments. Furthermore, we cannot predict the effect, if any, that any announcement or consummation of an acquisition or strategic investment transaction would have on the trading prices of our securities.

Our results of operations depend in part upon our ability to establish and protect our proprietary technology.

We rely on a combination of patents, trademarks, copyrights and trade secret laws to establish and protect our proprietary technology. We endeavor to obtain patents on our technology in Norway, the United States and the United Kingdom and in other jurisdictions that we consider important to our business. In addition, we enter into confidentiality and license agreements with our employees, and with consultants and companies from whom we acquire technology, and with others who have access to our proprietary technology. However, we do not patent all of our proprietary technology, and enforcement of proprietary technology rights may be difficult in some jurisdictions. Accordingly, the procedures we have taken to protect our proprietary rights may not be adequate to deter the misappropriation of our proprietary technology in all situations.

We depend on attracting and retaining qualified employees to develop our business.

The development of our business depends in large part upon our ability to attract and retain highly skilled and qualified personnel with the technical expertise required for our business. Our results of operations and financial condition could be adversely affected by increased labor costs or by any inability of our company in the future to hire, train and retain a sufficient number of qualified employees.

Risk Factors Relating Primarily to Our Geophysical Business, Both Marine Geophysical and Onshore

We invest significant amounts of money in acquiring and processing seismic data for our multi-client data library without being certain about how much of the data we will be able to sell or when and at what price we will be able to sell the data.

We invest significant amounts in acquiring and processing seismic data that we own, which we call multi-client data. Our future multi-client data sales, including the timing of such sales, are uncertain and depend on a variety of factors, many of which are beyond our control. By making such investments, we assume the risk that:

- we may not fully recover the costs of the data through future sales; and
- the value of our multi-client data could be adversely affected by, among other things, any adverse change in the general prospects for oil and natural gas exploration, development and production activities in the areas where we acquire multi-client data, by technological or regulatory changes and by other industry or general economic developments.

In particular, we own a significant amount of multi-client data offshore Brazil. As of December 31, 2005, the carrying value of our multi-client data offshore Brazil was $87.9 million. A further delay of sales in this region could have an adverse impact on our multi-client data sales.

In the past, we have incurred substantial impairment charges related to our multi-client data.

The amounts we amortize from our multi-client data library each period may fluctuate significantly, and these fluctuations can have a significant effect on our results of operations.

The manner in which we account for our multi-client data library has a significant effect on our results of operations. We amortize the capitalized cost of our multi-client data library based principally on the relationship of actual data sales for the relevant data to our estimates of total, including future, sales of data. Our sales estimates are inherently imprecise and may vary from period to period depending upon market developments and our expectations. Changes in the amounts and timing of data sales may result in impairment charges or changes in our amortization expense, which will affect our results of operations.

Substantial changes in amortization rates can have a significant effect on our results of operations.

We perform a portion of our contract seismic work under turnkey arrangements. If we bid too low on these contracts, we could incur losses on projects and experience reduced profitability.

Many of our contracts for seismic data acquisition are turnkey contracts, where our work is delivered at a predetermined and fixed price. In submitting a bid on a turnkey contract, we estimate our costs associated with the project. However, our actual costs can vary from our estimated costs because of changes in assumed operating conditions (including weather, fishing activity, interference from other seismic vessels and other operating disturbances), exchange rates and equipment productivity, among others. As a result, we may experience reduced profitability or losses on projects if our bids on turnkey contracts are too low and/or actual costs exceed estimated costs.

Our profitability could be negatively impacted by excess capacity in the geophysical industry.

When demand for marine seismic services increases, industry participants have previously responded by increasing capacity by building new seismic vessels or converting existing vessels for use in marine seismic operations. A significant increase in the industry's capacity could have an adverse effect on the pricing of our services and our profitability.

Risk Factors Relating Primarily to Our Production Business

Our operating results could suffer as a result of risks arising from our floating production, storage and offloading contracts.

Our floating production, storage and offloading contracts involve various risks, including risks of:

- failure to operate at high levels on a sustained basis for technical reasons, including operational difficulties that require modification of vessels or equipment, or due to strikes, employee lockouts or other labor unrest;
- reduced revenues to the extent that production decreases since all of our contracts contain a volume dependent tariff element;

- contract termination prior to the scheduled or anticipated expiration date for the contracts;
- failure to redeploy vessels following expiration or termination of long-term contracts; and
- failure of the underlying reservoir and/or the prevailing market prices for oil and natural gas to allow production of the expected amounts of oil and natural gas under contracts where our compensation depends to a significant degree on the amount of oil and natural gas produced.

Risk Factors Relating to Our Proposed Separation Transaction

Our proposed separation transaction could result in reduced liquidity, share price or market capitalization.

On March 27, 2006, our Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate our geophysical and production business and calling an extraordinary general meeting of our shareholders to vote on the transaction, to be held on April 28, 2006. If the transaction is approved by our shareholders and completed, our shares would be split into shares of two independently listed companies. There has been no prior market for shares of our production business on a stand-alone basis. Although our shares have been listed on the Oslo Stock Exchange and New York Stock Exchange, after the separation, our shares will represent shares in a smaller company. Moreover, subsequent to the separation, we will become a more specialized company, comprised exclusively of our geophysical business. As a result, our current shareholders may decide to sell shares after the separation if they consider us no longer appropriate for their investment portfolios. These facts could have a material adverse effect on the liquidity and share price of each of the new companies compared to our shares at present. The combined trading prices of shares after our proposed separation may not be equal to or greater than the trading price of our shares prior to the separation. For more information relating to our possible separation, see "Information on the Company — Proposed Separation of the Geophysical and Production Businesses" in Item 4 of this annual report. In addition, for more information about important factors relating to our proposed separation transaction, please refer to the disclosure document that we will make available to our shareholders in connection with the proposed separation.

Consummation of our proposed separation transaction is subject to the satisfaction or waiver of a number of conditions, and a separation may not be completed as currently contemplated.

Completion of our proposed separation transaction is subject to the satisfaction or waiver of a number of conditions, including:

- the receipt or waiver of all consents required in respect of the proposed separation;
- notice from the Oslo Stock Exchange that our production business will be accepted for listing immediately after the separation has been registered with the Norwegian Register of Business Enterprises and the new shares of our production business have been registered with the Norwegian Registry of Securities;
- evidence of the ability of our production business to satisfy its indebtedness;
- expiration of the deadline under Norwegian law for creditor objections and satisfaction of any creditor objections; and
- approval of the proposed separation by our shareholders.

These conditions may not be satisfied or waived, in which case the proposed separation transaction would not be consummated.

Our proposed separation transaction could have adverse tax consequences to us and the holders of our shares.

Our proposed separation transaction may have adverse tax consequences to us in certain jurisdictions. In addition, holders of our shares in certain jurisdictions may be subject to taxation as a result of the separation. For a more complete discussion of the tax aspects of our proposed separation transaction, please refer to the disclosure document that we will make available to our shareholders in connection with the proposed separation.

Other Risk Factors

We are a multinational organization faced with increasingly complex tax issues in many jurisdictions, and we could be obligated to pay additional taxes in various jurisdictions.

As a multinational organization, we are subject to taxation in many jurisdictions around the world with increasingly complex tax laws. The amounts of taxes we pay in these jurisdictions could increase substantially as a result of changes in these laws or their interpretations by the relevant taxing authorities, which could have a material adverse effect on our liquidity and results of operations. In addition, those authorities could review our tax returns and impose additional taxes and penalties, which could be material. We have identified issues in several jurisdictions that could eventually make us liable to pay material amounts in taxes relating to prior years. We also have an issue relating to the rate at which capital allowances can be claimed under the UK lease for *Petrojarl Foinaven*. Additional issues that we are not currently aware of may be identified in the future.

Because we are a foreign company and many of our directors and executive officers are not residents of the United States, you may have difficulty suing us and obtaining or enforcing judgments against us.

We are incorporated in the Kingdom of Norway, and substantially all of our current directors and executive officers reside outside the United States. All or a substantial portion of the assets of these persons and our company are located outside the United States. As a result, you may have difficulty:

- suing us or our directors and executive officers in the United States;
- obtaining a judgment in the Kingdom of Norway in an original action based solely on United States federal securities laws; and
- enforcing in the Kingdom of Norway judgments obtained in the United States courts that are based upon the civil liability provisions of the United States federal securities laws.

We could be adversely affected by violations of applicable anti-corruption laws.

We and our affiliated entities conduct business in countries known to experience government corruption. We are committed to doing business in accordance with our code of conduct, but there is a risk that we, our affiliated entities or our or their respective officers, directors, employees and agents may take action in violation of applicable anti-corruption laws, including the U.S. Foreign Corrupt Practices Act of 1977. Any such violations could result in substantial civil and/or criminal penalties and might adversely affect our business, results of operations or financial condition.

ITEM 4. *Information on the Company*

History and Development of the Company

Organization

Petroleum Geo-Services ASA is a public limited liability company established under the laws of the Kingdom of Norway in 1991. We are organized as a holding company that owns subsidiary companies. Our subsidiary companies conduct substantially all of our business. Unless we inform you otherwise or the context indicates otherwise, references to us in this annual report are to Petroleum Geo-Services ASA, its predecessors and its majority-owned subsidiaries. We maintain our headquarters and executive offices at Lysaker, Norway (Strandveien 4, N-1325, telephone: +47-67-52-64-00). Our registration number in the Norwegian Company Registry is 916235291. Our agent in the United States is CT Corporation System, 1633 Broadway, New York, New York 10019.

Who We Are

We are a technologically focused oilfield service company principally involved in providing geophysical services worldwide and providing floating production services in the North Sea. Globally, we provide a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, we own and operate four harsh environment floating production, storage and offloading ("FPSO") units.

In 2005 we managed our business in three segments as follows:

- *Marine Geophysical*, which consists of both streamer and seafloor seismic data acquisition, marine multi-client library and data processing;
- *Onshore*, which consists of all seismic operations on land and in very shallow water and transition zones, including our onshore multi-client library; and
- *Production*, which owns and operates four harsh environment FPSO units in the North Sea.

We manage our Marine Geophysical segment from Lysaker, Norway, our Onshore segment from Houston, Texas, and our Production segment from Trondheim, Norway.

On March 1, 2005 we sold Pertra AS, a small oil and natural gas company that we managed as a separate segment before the sale, to Talisman Energy (UK) Ltd. ("Talisman") as described in more detail below. Pertra was included in our reported numbers through February 2005. Pertra owned 70% of and was operator for Production License 038 ("PL038") on the Norwegian Continental Shelf ("NCS") and also owned participating interests in six additional NCS licenses without production. Pertra has been renamed Talisman Production Norge AS.

We also announced in September 2005 that we would convert our 4C ocean bottom crew operation, including the vessels *Ocean Explorer* and *Falcon Explorer*, to towed streamer vessels. The conversion was concluded in February 2006.

On March 27, 2006, our Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate our geophysical and production businesses and calling an extraordinary general meeting of our shareholders to vote on the transaction, to be held on April 28, 2006. If the transaction is approved by our shareholders and completed, our shares would be split into shares of two independently listed companies. For more information relating to our possible separation, see "Proposed Separation of the Geophysical and Production Businesses" below.

Historical Development

The primary milestones in our historical development include the following:

- *January 1991:* Company established with the merger of Geoteam a.s. and Nopec a.s.
- *August 1992:* Company ordinary shares listed on Oslo Stock Exchange
- *May 1993:* Initial public offering and listing in U.S. on NASDAQ
- *1995-1999:* Construction and deployment of six Ramform design 3D seismic vessels
- *April 1997:* Listing of our ADSs on the New York Stock Exchange
- *May 1998:* Acquisition of Golar-Nor (*Petrojarl I* and *Petrojarl Foinaven*)
- *October 1998:* Delivery of *Ramform Banff*
- *July 1999:* Acquisition of FPSO *Varg* (renamed *Petrojarl Varg*)
- *March 2001:* Sale of data management business and related software to Landmark Graphics Corporation, a subsidiary of Halliburton, and resumption of oil production by the re-tooled *Ramform Banff*

- *August 2002:* Acquisition of 70% ownership in, and operatorship of, PL 038 on NCS of the North Sea (including Varg field)
- *August-November 2002:* Replacement of various members of senior management, including the Chairman of the Board and Chief Executive Officer and the Chief Financial Officer, with a new non-executive Chairman of the Board, a new Chief Executive Officer and a new Chief Financial Officer
- *February 2003:* Sale of Atlantis subsidiary to Sinochem
- *February 2003:* Delisting of ADSs from the New York Stock Exchange and quotations for ADSs available through Pink Sheets
- *July 2003:* Filing under Chapter 11 of U.S. Bankruptcy Code
- *November 2003:* Emergence from Chapter 11 proceedings, reorganization plan becomes effective and new Board of Directors takes office
- *December 2004:* Re-listing of our ADSs on the New York Stock Exchange following filing of Form 20-F for 2003 fiscal year
- *March 2005:* Sale of oil and natural gas subsidiary Pertra to Talisman
- *November 2005:* Announcement of intention to explore possible separation of our geophysical and production businesses into two independently listed companies
- *December 2005:* Completion of refinancing of $746 million of 10% senior notes and $110 million credit facility with a $1 billion senior secured credit facility
- *February 2006:* Announced a proposed joint venture with Teekay Shipping Corporation to develop new FPSO projects
- *March 2006:* Announcement of a project to build a new and enhanced Ramform seismic vessel
- *March 2006:* Authorization by our Board of Directors to demerge our production business, to be operated under the name "Petrojarl"

2005 Developments

Our primary business achievements in 2005 were:

- we improved our strong safety performance
- we achieved a strong full year cash flow and a significant debt reduction
- we significantly improved our marine seismic contract operating profit margins
- we increased marine multi-client late sales by 8% compared to 2004, despite three years of low multi-client investments
- we sold our oil and gas subsidiary Pertra
- we repaid from available cash or refinanced the majority of our debt to provide greater operating flexibility and lower borrowing costs

In addition, during the first three months of 2006 we have:

- acquired the shuttle tanker *Rita Knutsen* for a possible FPSO conversion
- announced a proposed joint venture with Teekay to develop new FPSO projects
- announced a project to build a new and enhanced Ramform seismic vessel for delivery in early 2008
- decided to propose to our shareholders a demerger of our production business, to be operated under the name "Petrojarl"

Proposed Separation of Our Geophysical and Production Businesses

We currently conduct our business in two primary business areas:

- our geophysical business, which includes our Marine Geophysical and Onshore operations, and
- our production business.

Historically, the geophysical business and the production business have been organized and operated as separate businesses.

On March 27, 2006, our Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate our geophysical and production businesses into two independently listed companies and calling an extraordinary general meeting of our shareholders to vote on the transaction, to be held on April 28, 2006.

Under the proposed demerger, our subsidiary companies that conduct the production business, and the assets, rights and liabilities related to the production business, will be transferred to a wholly owned subsidiary named Petrojarl ASA. Our subsidiary companies that conduct the geophysical business, and the assets, rights and liabilities related to the geophysical business, will be retained under Petroleum Geo-Services ASA.

When the separation is completed, each holder of our ordinary shares will receive one ordinary share of Petrojarl for each of our shares held and each holder of American Depositary Shares (''PGS ADSs'') representing our ordinary shares will receive one newly issued American Depositary Share representing an ordinary share in Petrojarl (''Petrojarl ADSs'') for each PGS ADS held. We intend to apply for a listing of the ordinary shares of Petrojarl ASA on the Oslo Stock Exchange. We do not intend to list the Petrojarl ordinary shares or Petrojarl ADSs in the U.S.

Immediately after consummation of the demerger, PGS ASA would hold shares in Petrojarl representing a 19.99% interest in Petrojarl and the Petrojarl shares issued to the holders of our shares and the PGS ADSs would represent the remaining 80.01% interest in Petrojarl. Subject to prevailing market conditions and other factors, PGS ASA expects to sell the shares in Petrojarl in a public offering in conjunction with the consummation of the separation and demerger.

If the demerger plan is approved by the requisite two-third vote of our shareholders and the conditions precedent to consummation of the demerger are satisfied, or where applicable waived, we currently expect the demerger to be consummated in July 2006.

After completion of the demerger, PGS ASA will continue our geophysical business and hold its assets, rights and liabilities.

Upon consummation of the separation, we expect that Petrojarl will have a new $425 million five year borrowing facility and will initially borrow $325 million under the facility. The proceeds from the initial borrowing, together with any proceeds from any sale of all or any part of the Petrojarl shares retained by PGS ASA, will be used by PGS ASA for repayment of existing debt or other purposes. As part of the separation transaction, Petrojarl will receive cash and cash equivalents of approximately $50 million and will have approximately $275 million of net interest-bearing debt immediately following consummation of the separation.

In connection with the demerger, we have entered into other agreements, subject to final documentation, either as part of the proposed demerger plan or otherwise, to facilitate the demerger. For our UK leases on three of our Ramform seismic vessels and the production equipment for the *Ramform Banff*, we have entered into agreements, subject to final documentation, with the lessors providing for certain options with respect to the termination of the leases at reduced termination fees, subject to completion of the demerger. If all of such leases were terminated, we would be required to pay termination fees of up to 13 million British pounds (approximately $23 million). Upon termination, we and, in the case of *Ramform Banff,* Petrojarl would become the owner of the assets and avoid any additional rental payments relating to these UK leases. In addition, we have reached an agreement, subject to final documentation, with the operator of *Petrojarl Foinaven* to provide the benefit of financial covenants that would apply to Petrojarl following the demerger and to make other amendments to the existing contractual arrangements, in each case subject to completion of the demerger and certain other conditions. We will provide more detailed information related to the separation and demerger, as well as the other agreements, in a shareholder information statement prior to the extraordinary general meeting of our shareholders called to consider the separation and demerger, which we expect to occur in April 2006.

Sales of Atlantis and Tigress Subsidiaries

In February 2003, we sold our Atlantis oil and natural gas subsidiary to China National Chemicals Import and Export Corporation for a combination of $48.6 million in cash, the reimbursement of $10.6 million of expenditures and the right to receive additional future payments of up to $25.0 million if certain contingent events occur. The sale agreement was amended in June 2005 and now provides that we may receive a maximum of $10.0 million if certain contingent events occur. In March 2006, we received confirmation of the occurrence of certain of these events that entitle us to receive $6 million, of which $3 million was received in March 2006.

In December 2003, we sold our software subsidiary, PGS Tigress (UK) Ltd., for a deferred compensation payable in 2004 and 2007 of $1.8 million in the aggregate, for which payments were received in December 2005 and 2004. We may also receive additional contingent proceeds based on performance of the company through 2006.

Sale of Our Oil and Natural Gas Subsidiary Pertra

On March 1, 2005, we sold our wholly owned subsidiary Pertra AS to Talisman for an initial sales price of approximately $155 million, which resulted in a gain of $149.8 million, including the $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg* as described below.

As a part of the agreement with Talisman, we are entitled to an additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006 we received $8.1 million, representing the 2005 portion of the contingent consideration, and recognized that amount in 2005 as an additional gain from the sale.

We also granted an option enabling Talisman to change the termination clause with respect to *Petrojarl Varg*. The option expired on February 1, 2006, without being exercised. We are entitled to terminate the agreement if the average normal production from the Varg field falls below 15,700 barrels per day. Based on the current production profile of the Varg field, *Petrojarl Varg* could become available for redeployment on a new field in 2008.

The table below shows revenues and operating profit (loss) as if Pertra had not been included in our consolidated results for the periods presented.

	Years Ended December 31,	
	2005	2004
	Unaudited	Unaudited
	(In millions of dollars)	
Revenues	$1,170.1	$1,017.5
Operating profit	177.7	9.5

For additional information about our acquisitions and dispositions, please read note 24 of the notes to our consolidated financial statements in Item 18 of this annual report.

Our Business Priorities

Following the sale of Pertra, significant debt reduction and a successful refinancing, we intend to create value for our shareholders through establishing our geophysical and production businesses as separate and focused companies. On March 27, 2006, our Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate our geophysical and production businesses and calling an extraordinary general meeting of our shareholders to vote on the transaction, to be held on April 28, 2006. If the transaction is approved by our shareholders and completed, we will continue the geophysical business in our company, while the production business will be discontinued as part of our company and continued through the separate company Petrojarl ASA which will be listed the Oslo Stock Exchange. Please see "Proposed Separation of the Geophysical and Production Businesses" above for more information on the proposed separation. Our main priority in the short term is to successfully complete the separation and position both companies for growth.

We intend to continue our focus on health, safety and environment ("HSE") performance and strengthening internal controls, corporate governance and human resource capabilities.

Within Marine Geophysical, we intend to maintain our emphasis on higher acquisition productivity and regularity in our operations and in customer delivery. We will seek to enhance the productivity advantage of our Ramform vessels through increasing the streamer count. We will seek to expand our market share in the data processing business and invest prudently in technology, equipment and multi-client seismic data.

Within Onshore, we aim to utilize fully our present equipment, while pursuing a broader, but selective geographical market exposure.

Within our Production segment, we intend to maintain our position as a leader in harsh environment operations, while seeking growth opportunities in and outside the North Sea, primarily through the planned Teekay Petrojarl Offshore joint venture.

Our Geophysical Services

Overview

We manage our geophysical services through two segments:

- *Marine Geophysical*, which consists of streamer seismic data acquisition, marine multi-client library and data processing; and

- *Onshore*, which consists of all seismic operations on land and in very shallow water and transition zones, including our onshore multi-client library.

Our geophysical services business is one of the major global participants in the acquisition of marine three-dimensional (3D) seismic data. This business acquires, processes, interprets, markets and sells seismic data worldwide that is used by oil and natural gas companies to help them find oil and natural gas and to determine the size and structure of known oil and natural gas reservoirs. In our seismic projects, we are involved in planning the seismic surveys and acquiring and processing the seismic data. Oil and natural gas companies use this information in evaluating whether to acquire new leases or licenses in areas with potential accumulations of oil and natural gas, in selecting drilling locations, in modeling oil and natural gas reservoir areas and in managing producing reservoirs. Oil and natural gas companies use 4D or time lapse surveys, which are surveys produced by the repetition of identical 3D surveys over time, to assist in their evaluation of subsurface geophysical conditions that change over time due to the depletion and production of reservoir fluids. This evaluation provides for more efficient production of the reservoir and the possible extension of the reservoir's useful life. We use our High Density 3D — HD3D℠ — technology to acquire 3D data with higher trace densities, giving improved resolution of the subsurface and higher quality images of the reservoirs.

We acquire seismic data both on an exclusive contract basis for our customers and on our own behalf as multi-client data for licensing from time to time to multiple customers on a non-exclusive basis. In some of our projects, we share interests in the revenue from the sales of the multi-client data with third parties. During 2005, we used our active seismic vessel acquisition capacity, measured by time, approximately 91% to acquire contract data and approximately 9% to acquire multi-client data.

During 2005, we:

- continued our strong HSE performance;
- continued our focus on contract seismic;
- increased our investments in multi-client seismic while at the same time achieved a pre-funding ratio of 101% of cash investments in the multi-client library;
- increased the level of our late-sales of multi-client data, despite three years of relatively low investments in multi-client data;
- increased significantly our contract order backlog in Marine Geophysical; and
- strengthened our Onshore operations with the commencement of new significant contracts in Africa.

Our Strategies for Geophysical Services

Our principal strategies for our geophysical services include:

- capitalizing on our strong cost position and operating performance through the Ramform concept;
- increasing our operating margins on existing acquisition capacity by:
  - reducing steaming and downtime in Marine Geophysical,
  - increasing our focus on survey project planning and execution,
  - entering selected new geographic areas in Onshore,
  - focusing our work where premium pricing is available,
  - selectively increasing our streamer count, and
  - investing in more effective acquisition capacity;
- maximizing the value of our multi-client data library by:
  - increasing our investments in our multi-client library with strong emphasis on prospectivity and high pre-funding,
  - strengthening our emphasis on the target selection process and assessment of prospectivity,
  - enhancing our existing library through reprocessing, and
  - re-entering the Gulf of Mexico with selective investments;
- capturing the full potential in our data processing centers and increasing our market share, especially in high-end processing;
- commercializing and investing in new technology and equipment, including new streamers, to increase productivity on our unique Ramform seismic vessels and our HD3D℠ seismic solution; and
- positioning ourselves to participate in restructuring or acquisition opportunities on an advantageous basis.

In the past, we have invested heavily in our multi-client seismic data library and in high technology acquisition equipment, including:

- our Ramform seismic vessels;
- our high capacity computing facilities, together with the development of specialized proprietary software for seismic imaging, multi-component processing, signal enhancement and visualization technology; and
- state-of-the-art technology in our onshore seismic data acquisition equipment to enable efficient acquisition of high quality seismic data in varied terrain.

We believe that our main competitive strengths within our geophysical services businesses include:

- our highly experienced work force;
- high operational reliability, safety and customer satisfaction;
- our ability to tow more streamers and our superior streamer retrievability, control and stability, which yield better cost effectiveness on surveys and in adverse weather conditions, respectively;
- our high technology Ramform seismic vessels; and
- the high channel counts and standardized equipment for our onshore operations.

Geographic Areas of Operation

We have divided our Marine Geophysical business into three primary areas of operations:

- North and South America;
- Europe, Africa and the Middle East; and
- Asia Pacific.

We have divided our Onshore geophysical business into three primary areas of operations:

- North America (U.S. and Canada);
- Latin America (Mexico and South America); and
- Eastern Hemisphere.

We acquire seismic data in most of the active oil and natural gas exploration or production areas around the world, including:

- offshore and onshore Canada;
- the Gulf of Mexico;
- onshore in the U.S. mid continent, Rocky Mountains and Alaskan North Slope regions;
- offshore and onshore Mexico and other parts of Latin America;
- offshore Brazil;
- the North Sea;
- the Mediterranean and Black Seas;
- offshore West Africa, including shallow water areas;
- the Middle East and North Africa;
- the Caspian Sea area;
- offshore China and Korea;
- offshore India and onshore Bangladesh;
- offshore in the Sakhalin area of Russia; and
- offshore Australia, Indonesia and other countries in the Asia Pacific region.

Contract and Multi-Client Operations

Contract Operations. When we acquire seismic data on a contract basis, our customers direct the scope and extent of the survey and retain ownership of the data obtained. Contracts for seismic data acquisition, which are generally awarded on a competitive bid basis, may include both a day-rate and a production rate element. Under these contracts, the customer assumes primary responsibility for interruption of acquisition operations due to factors that are beyond our control, including weather and permitting. Contracts are also awarded on a turnkey basis. With turnkey contracts, the customers pay based upon the number of seismic lines or square kilometers of seismic data collected and we often bear some or all of the risk of interruption of operations due to factors that may be beyond our control.

During 2005, we used 91 percent of our active streamer 3D vessel acquisition capacity, measured by time, to acquire seismic data on contract basis. We performed contract operations during 2005 in the North Sea; onshore in the U.S. mid-continent; onshore Canada; onshore Mexico; onshore South America; offshore Brazil; offshore West Africa, including shallow water; offshore North Africa; onshore Bangladesh; and offshore Australia, Thailand and other countries in the Asia Pacific region.

Multi-Client Operations. From the perspective of an oil and natural gas company, licensing multi-client seismic data on a non-exclusive basis is typically less expensive on a per unit basis than acquiring the seismic data on an exclusive basis. From our perspective, multi-client seismic data can be more cost effective to acquire and may be sold a number of times to different customers over a period of years. As a result, multi-client seismic data has the potential to be more profitable than contract data. However, when we acquire multi-client seismic data we assume the risk that future sales may not cover the cost of acquiring and processing such seismic data. Obtaining pre-funding for a portion of these costs reduces this risk, and increasingly we require a relatively high level of pre-funding before beginning a project. We determine the level of pre-funding that we will require before initiating a multi-client seismic survey by evaluating various factors affecting the sales potential of each survey. These factors include:

- the existence, quality and age of any seismic data that may already exist in the area;
- the amount of leased acreage in the area;
- whether or when an award of a license to explore and develop an area for production to be covered by a survey is expected to be granted;
- the prospectivity of the area in question for hydrocarbons and for future licenses of multi-client data;
- the existing infrastructure in the region to transport oil and natural gas to market;
- the historical turnover of the leased acreage;
- the political and economic stability of the countries where the data are to be acquired; and
- the level of interest from oil and natural gas companies in the area.

We own a significant library of marine multi-client data in most of the major oil and natural gas basins of the world, including the Gulf of Mexico, the North Sea, offshore West Africa, offshore Brazil and the Asia Pacific region. Our onshore library is entirely in North America. During both 2004 and 2003, we reduced substantially the amount we invested in new multi-client data, as compared to earlier years, and devoted a higher portion of our capacity to the contract market. In 2005 our multi-client investments increased by 35% compared to 2004.

In our multi-client operations, we make initial sales of the data prior to project completion, which we refer to as pre-funding sales, and we refer to all further sales as late sales. We make a substantial portion of these late sales in connection with acreage license round activity in those regions where we have a data library. Typically, customers are required to pay an amount for access to the data and additional amounts, or uplift fees, upon award of a concession or sometimes upon execution of a production sharing or similar contract. The timing and regularity of such license round activity varies considerably depending upon a number of factors, including in particular the geopolitical stability of the region in question. As a result, both the total amount and the timing of late sales can be difficult to forecast accurately, with potentially significant revenue swings from quarter to quarter and from year to year.

We attempt to protect our multi-client seismic data from misuse by customers primarily through contractual provisions that permit the use of the data only by that particular customer on a nontransferable basis. Such provisions can be effective only if misuse of the data by customers or third parties can be detected and if our rights can be enforced through legal action.

Our multi-client data is marketed primarily through our own sales organization.

Data Processing

We provide seismic data processing services for our own seismic data acquisition operations and for third parties. Generally, we compete for data processing contracts on a competitive bid basis. These contracts generally provide for the customer to pay a flat fee per square kilometer processed for a prescribed set of processing procedures. Additional procedures may be quoted separately and are often added during the course of a project.

We operate our data processing division as a part of our regional Marine Geophysical business unit. Technical support, research and development and computer operations operate on a global basis. As of December 31, 2005, we operated fifteen land-based seismic data processing centers, with the largest centers being located in Houston, Texas, U.S.; London, England and Perth, Australia. The largest seismic processing centers utilize computer resources organized in a global computer resource organization (Mega-Center). The three centers in Houston, London and Perth are inter-connected through high capacity network links. In addition, most of our marine seismic crews have the capability to perform data processing onboard the vessel.

Through our seismic data processing operations we provide:

- 2D and 3D data processing of onshore and marine seismic surveys;
- onboard (vessel) seismic data processing for reduced delivery times and enhanced real-time quality control for data that we acquire;
- multi-component and 4D seismic data processing for reservoir characterization and monitoring;
- special process design to exploit the dense sampling of our HD3D℠ data acquisition;
- specialized depth imaging of subsurface structures; and
- other specialized signal enhancement techniques.

Our Marine Geophysical Segment

Marine Acquisition. We believe that we operate one of the most advanced marine seismic data acquisition fleets in the world. As of December 31, 2005, we had a total of ten 3D marine seismic streamer crews operating seismic vessels, and we had one seafloor seismic crew.

Streamer Seismic Acquisition. Our conventional streamer operations represent the largest part of our marine seismic data acquisition business. In our streamer operations, we use our seismic vessel fleet to acquire 3D, 4D and HD3D℠ seismic data as described above under "Our Geophysical Services — Overview." For information relating to our fleet of vessels used to acquire marine seismic data, see "Vessel Fleet and Crews" below.

Seafloor Seismic Acquisition. We use seafloor seismic acquisition in areas where conventional streamer acquisition operations are not possible or economically feasible due to access limitations from shallow water or obstructions. Seafloor seismic acquisition is also used in areas where conventional streamer acquisition would not meet the desired geophysical objectives. In 2005 we had one seafloor seismic crew that utilized a recording vessel, a source vessel and a cable-laying vessel. In September 2005 we announced that we would convert the seafloor seismic crew operations to streamer operations. One of the three vessels was converted to a six streamer 3D vessel, one was converted to a 2D vessel, and the third vessel was returned to its owners. The conversion was completed in February 2006.

Vessel Fleet and Crews. We acquire marine seismic data using seismic crews primarily through owned and chartered vessels that have been constructed or modified to our specifications and outfitted with a complement of data acquisition, recording, navigation and communications equipment. Our crews direct the positioning of a vessel using sophisticated navigation equipment, deploy and retrieve streamers, cables, receivers and energy sources, and operate all of the seismic systems. Our seismic crews do not operate the vessels. The vessel maritime crews are employees of either the owner of the chartered vessels or a contract operator for our vessels.

Most of our seismic vessels have an equipment complement consisting of the following:

- recording instrumentation;
- digital recording streamers;
- acoustic positioning systems for source and streamer locations;
- multiple navigation systems for vessel positioning; and
- except for vessels that record only, a source control system that controls the synchronization of the energy sources and an air gun array firing system that activates the acoustic energy source.

We provide in the following table information as of December 31, 2005 about our marine seismic data acquisition vessels.

Vessel Name	Year Rigged/ Converted	Total Length (Feet)	Total Beam (Feet)	Maximum Streamer Capability	Maximum Streamers Deployed (through December 31, 2005)	Owned or Charter Expiration
3D Seismic Vessels:						
Ramform Explorer	1995	270	130	12	12	Owned
Ramform Challenger	1996	284	130	16	12	Owned(1)
Ramform Valiant	1998	284	130	20	12	2023(1)
Ramform Viking	1998	284	130	20	12	2023(1)
Ramform Victory	1999	284	130	20	16	2024(1)
Ramform Vanguard	1999	284	130	20	12	2024(1)
Atlantic Explorer	1994	300	58	6	6	Owned
American Explorer	1994	300	72	8	8	Owned
Nordic Explorer	1993	266	54	6	6	Owned
Orient Explorer	1995/96	246	49	4	4	2006(2)
Seafloor Seismic Vessels:						
Falcon Explorer	1997	266	53	N/A	N/A	Owned(4)
Bergen Surveyor	1997	217	48	N/A	N/A	2006(3)
Ocean Explorer	1993/95	269	59	N/A	N/A	Owned(4)
Support Vessels:						
Remus	1998	136	32	N/A	N/A	Owned
Romulus	1997	118	34	N/A	N/A	Owned

(1) We have UK lease arrangements for each of the *Ramform Valiant*, the *Ramform Viking*, the *Ramform Victory*, the *Ramform Vanguard* and the *Ramform Challenger*. Under the leases, we lease the vessels under long-term charters that give us the option to purchase the vessels for a *de minimis* amount at the end of the charter periods. The leases are legally defeased because we have made payments to banks in consideration for which the banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. Please read notes 2 and 20 of the notes to our consolidated financial statements included in Item 18 of this annual report.

(2) The charter agreement for *Orient Explorer* has a one-year term and will be extended annually for another year until 2011, unless we terminate the charter by giving three months' notice.

(3) We have terminated the charter for *Bergen Surveyor* and the vessel was returned to its owners in the first quarter of 2006.

(4) *Falcon Explorer* was converted to a 2D vessel and *Ocean Explorer* was converted to a six streamer 3D vessel in the first quarter of 2006.

In March 2006, we announced that we intend to build a new third generation Ramform seismic vessel at Aker Yards, Langsten, Norway. We currently expect delivery in the first quarter of 2008. We expect the new vessel to cost approximately $85 million, excluding the cost of seismic equipment, and we expect the total cost to be approximately $160 million, excluding project management cost and interest. We intend to seek an option to build a sister vessel at the same yard. Aker Yards has constructed all six of our Ramform vessels, and this is our first new build since 1999. The third generation Ramform will be designed with the objective of further extending our lead in 3D seismic acquisition productivity and efficiency, and will be a key step in the implementation of our HD3D℠ technical strategy.

Competition in Our Marine Geophysical Segment. The seismic data acquisition and processing businesses are very competitive worldwide for both the contract market and the multi-client market. We compete for available seismic surveys based on a number of factors, including technology, price, performance, dependability, vessel availability, turnaround time and processing capacity availability. Our largest competitors on a global basis are WesternGeco, a joint venture between the seismic units of Schlumberger Limited and Baker Hughes Incorporated, Compagnie Generale de Geophysique, S.A. and Veritas DGC Inc.

All of our major competitors in the seismic business both acquire and process 3D seismic data. Our processing operations compete primarily with WesternGeco, Compagnie Generale de Geophysique and Veritas DGC for time processing contracts. For depth imaging and other advanced processing applications, we also compete with several smaller processing companies. We compete for time processing contracts based primarily on price and technology, but processing capacity, turnaround time and processing center location are also important factors.

Our Onshore Segment

Our Onshore segment consists of seismic acquisition operations on land and in very shallow water and transition zones. This segment also includes our onshore multi-client library. We conduct contract onshore seismic acquisition throughout the world. Our onshore multi-client library is entirely in the United States. During 2005, we conducted seismic acquisition operations in the United States (Gulf Coast, mid-continent, Rocky Mountains and Alaska), Canada, Mexico, Venezuela, Nigeria and Bangladesh. During 2005, active crew counts have ranged from five to nine. As of December 31, 2005, we had seven crews conducting activities in the United States, Canada, Venezuela, Nigeria and Bangladesh. As of that date, we were also in the process of starting up operations in Alaska, Mexico and Libya. We are pursuing additional contract opportunities in selected markets worldwide and are expanding our multi-client onshore library in the U.S. mid-continent.

In the market for onshore seismic services, we are one of the larger worldwide operators, measured in terms of revenues. We compete in the onshore segment based on price, crew availability and other factors. We believe that we can remain competitive by capitalizing on our project execution and management skills and by continuing to provide a high quality technical product. The majority of our recording equipment pool is relatively uniform, facilitating changing crew counts and channel counts on any specific crew as the market dictates.

Our Production Segment

On March 27, 2006, our Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate our geophysical and production businesses and calling an extraordinary general meeting of our shareholders to vote on the transaction, to be held on April 28, 2006. If the transaction is approved by our shareholders and completed, our shares would be split into shares of two independently listed companies. For more information relating to our possible separation, see "Proposed Separation of the Geophysical and Production Businesses" above.

Overview

We are one of the largest operators of FPSO vessels in the North Sea, measured by production capacity and number of vessels. Through our Production segment, we own and operate four FPSO vessels with a combined production capacity of 339,000 barrels of oil per day and a crude oil storage capacity of one million barrels. All four of our FPSOs, the *Ramform Banff, Petrojarl I, Petrojarl Foinaven* and *Petrojarl Varg*, are double hulled, rated for harsh environments and capable of working in deepwater fields.

We believe that our fleet of FPSO vessels is one of the most technologically advanced in the industry. We have experience operating in some of the industry's most demanding environments in the North Sea and the continental shelf of the Atlantic Ocean.

An FPSO system is a ship-based type of mobile production unit that produces, processes, stores and offloads oil and processes, re-injects or exports gas from offshore fields with widely differing production characteristics, sizes and water depths. The selection of a particular mobile production unit from among the several types of readily movable offshore production systems depends on several factors, including overall reservoir and environmental characteristics of the field to be developed, availability of transportation infrastructure and financial and schedule constraints. FPSO systems typically perform the same function as fixed offshore platforms in the offshore production of oil and natural gas, with the exceptions of drilling and heavy well maintenance. However, FPSO systems generally provide a number of advantages over fixed platforms, including:

- being capable of storing and offloading oil;
- being suitable for a wide range of field sizes and water depths;
- being reusable on more than one developed reservoir;
- generally costing less and being easier to install and remove than fixed platforms; and
- reducing the time from the discovery of oil and natural gas to production.

Our FPSO Strategy

Our strategy for production services includes:

- maximizing the value of our present contracts through careful cost management,
- maximizing future redeployment opportunities, and
- seeking growth opportunities through a proposed joint venture with Teekay Shipping Corporation to establish a broader geographical position.

We believe opportunities exist in the North Sea, particularly on the Norwegian Continental Shelf where we currently operate two vessels, to redeploy our FPSO vessels when our existing FPSO contracts terminate. We also intend to continue to evaluate redeployment opportunities in other regions.

Proposed Joint Venture with Teekay

In February 2006, we announced a proposed joint venture with Teekay Shipping Corporation to develop new FPSO projects. We expect to finalize the arrangements for this joint venture during the second quarter of 2006.

We believe the agreement with Teekay will be an important part of the international expansion strategy for our production business. The joint venture allows us more effectively to pursue further growth in the market for mobile production solutions worldwide. Teekay has a global marketing organization and customer and shipyard relationships, which complements our engineering expertise and experience as a quality operator of FPSOs in the harsh North Sea environment.

Teekay has a fleet of more than 140 tanker vessels, offices in 15 countries and 5,100 seagoing and shore-based employees.

The FPSO Market

The market for production services differs fundamentally from the geophysical market. Offshore production generally takes place a relatively long time after exploration drilling has been completed. As a result, oil and natural gas companies typically make production-related decisions based on different financial parameters than those used for decisions relating to seismic or drilling activities. As offshore hydrocarbon basins around the world in general have matured, oil and natural gas companies in a number of oil producing areas have increasingly focused on the development of smaller fields with relatively smaller or uncertain reservoir estimates or shorter expected producing lives. For development of these smaller fields to be profitable, the oil and natural gas companies must reduce development cost levels and financial exposure. As a result, producers have focused increasingly on subsea installations and reusable FPSO systems instead of the more traditional fixed steel and concrete platforms, which generally are not reusable.

Our FPSO Systems

We provide in the following table information as of December 31, 2005 about our four FPSO vessels. In addition to these four vessels, as of December 31, 2005 we used two shuttle tankers and one storage tanker from third-party contractors under operating leases expiring at various dates through 2014. In addition, as of December 31, 2005 we owned a 40% interest in a French company that owns the FPSO *Ikdam*, which is producing the Isis field located offshore Tunisia on a fixed day rate contract. As of that date, production from this vessel was approximately 1,500 barrels per day with a maximum processing capacity of 30,000 barrels per day.

FPSO Vessel Name	Year Delivered	Approximate Total Length (Feet)	Approximate Total Width (Feet)	Production Capacity (Barrels of Oil per Day)	Displacement (Metric Tons)	Storage Capacity (Barrels)
Ramform Banff(1)	1998	395	175	95,000	32,100	120,000
Petrojarl I	1986	683	105	47,000	51,000	180,000
Petrojarl Foinaven(1)	1996	827	116	140,000	72,000	280,000
Petrojarl Varg	1999	702	125	57,000	100,000	420,000

(1) We have UK lease arrangements for the *Petrojarl Foinaven* and for the *Ramform Banff* topside production equipment. Under the leases, we lease the vessel and equipment under long-term charters that give us the option to purchase the vessel and equipment for a *de minimis* amount at the end of the charter periods. The leases are legally defeased because we have made payments to banks in consideration for which the banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. Please read notes 2 and 20 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Ramform Banff

The *Ramform Banff* operates on the Banff field, located in the UK sector of the North Sea about 120 miles east of Aberdeen, Scotland. Our contract for this work dates to 1997, and oil production from the field commenced in January 1999. In 2005, the wells from the nearby Kyle field were connected to the *Ramform Banff.*

Under the existing contract with the field operator, we will continue to produce the Banff field with the *Ramform Banff* until the end of the life of the field, which is estimated to be 2014. The new contract contains a two-tier production-dependent tariff that varies at different production levels. We receive $5 per barrel of oil produced per day up to 15,400 barrels and $3 per barrel of oil produced per day in excess of 15,400 barrels. We also receive a fixed day rate of £40,000 (approximately $69,000) per day, with a minimum total rate of $126,800 per day. These rates are applicable for production through 2014, with provisions for cost index adjustments. If field production extends beyond 2014, we will be entitled to an increased day rate. Under the amended contract, the field operator has the right to terminate the contract at its sole discretion on six months' notice. Upon termination of the contract, the field operator has the option to acquire the sub-sea facilities of the *Ramform Banff* free of charge or cost. In the event that the field operator does not exercise its option, we are obligated to remove the sub-sea facilities at our cost and, upon completion of our obligations under the contract, the operator will owe us five million British pounds, escalated by 1.5% per annum from 2000.

Petrojarl I

We operate the *Petrojarl I* under contract to Statoil to produce the Glitne field in the Norwegian sector of the North Sea. We began production of the field with the *Petrojarl I* in August 2001. Based on production estimates filed by the operator, we expect that production under the contract may continue beyond 2008.

The contract provides for compensation consisting of a tariff-based element of $3.50 per barrel and a fixed day rate of $12,750 plus up to $5,000 per day for water injection, subject to a minimum of $58,500 and a maximum of $108,500. In addition, we are entitled to receive an additional amount of NOK 475,585 (approximately $70,262) per day for operating expenses. Statoil may cancel the contract on six months' notice. In addition, Statoil may terminate the contract upon specified force majeure events; the insolvency or bankruptcy of our subsidiary K/S Petrojarl I A/S or demonstration by that subsidiary that it is not capable of performing the work; or our substantial breach of the contract. We may cancel the contract on three months' notice if the minimum variable rate has been received for 90 days in a 120 day period, subject, however, to Statoil's right to continue the contract by increasing the tariff element.

Petrojarl Foinaven

The *Petrojarl Foinaven* is under contract to a consortium of field co-operators led by Britoil PLC, a subsidiary of BP plc, for production of the Foinaven field west of the Shetlands. The Foinaven contract is not limited as to time. Britoil may terminate the contract with a minimum of two years' notice. We currently expect that the vessel will remain on the field for a substantial period. Britoil may terminate the contract upon the total loss of the vessel, a breach of the contract that is not remedied within agreed deadlines, specified insolvency and bankruptcy related events or specified force majeure events. In addition, we may terminate the contract with prior notice if production-dependent tariff revenue falls below specified levels.

The contract provides for compensation consisting of a fixed day rate of $71,258 and a two-tier production-dependent tariff that varies at different production levels. We receive $3.50 per barrel of oil produced per day up to 25,000 barrels and $2.95 per barrel of oil produced per day in excess of 25,000 barrels, and we receive $0.75 per barrel of oil produced per day from East Foinaven.

We have additional obligations that may arise under the contract relating to the Foinaven project, including obligations to:

- compensate Britoil up to a maximum of $10 million for breaches of contract; and
- pay for pollution damage caused by diesel or lubricants.

Petrojarl Varg

The *Petrojarl Varg* produces the Varg field on the Norwegian Continental Shelf of the North Sea under a contract with the license owners of PL038. Under the existing charter and operating agreement with the PL 038 license owners, our compensation consists of a fixed base day rate of $90,000 and a tariff of $6.30 per barrel produced per day. The charter and operating agreement may be terminated with 90 days written notice, but we are not entitled to terminate the agreements as long as the mean weekly production during normal operation on the license exceeds approximately 15,700 barrels of oil per day. According to the current production profile of the Varg field, *Petrojarl Varg* could be available for redeployment on a new field in 2008.

Competition in Our Production Operations

Our production operations generally compete with oil companies deciding to operate FPSOs themselves, with other FPSO operators, with fixed installations and tension leg platforms, with sub-sea production installations tied back to existing infrastructure, with semi-submersible and jack-up platforms and with other floating or land-based production systems. Competition between FPSO systems and other offshore production systems is based on a number of factors including water depth, the availability or proximity of transportation infrastructure, the size of the producing field and time considerations, estimated reserves, the cost and schedule for modifications, as well as local regulatory framework. Competition tends to be limited within segments of processing plant sophistication, operating conditions and regulatory regimes, as FPSO systems having different specifications cannot be redeployed easily or cost effectively between these segments. Our fleet of FPSOs is designed specifically for harsh weather operations, limited shuttling distances and demanding regulatory regimes, such as typically found in the North Sea and the Atlantic Continental Shelf. The limited shuttling distances required for our FPSOs results in relatively low need for storage capacity. In addition to the FPSO operations and other offshore production systems of the major oil and natural gas companies, our FPSO competitors include numerous companies that own a small number of FPSO vessels.

FPSOs perform similar tasks as fixed installations, with the exception of drilling and heavy well maintenance. To combine drilling and heavy well maintenance with production, some oil companies have opted for semi-submersible platforms. The choice of development system between an FPSO and either a fixed installation or another floating system is dependent on an overall technical and financial evaluation of the individual field to be developed.

Oil and Natural Gas Production Segment (Pertra)

We sold Pertra to Talisman on March 1, 2005 as described in more detail under "Operating and Financial Review and Prospects — Sale of Our Oil and Natural Gas Subsidiary Pertra" in Item 5 of this annual report. The operations of Pertra were included in our results of operations through February 2005. Following our sale of Pertra, we do not have any continuing direct economic interest in the activities of Pertra except for certain additional contingent sales proceeds as described under "Operating and Financial Review and Prospects — Sale of Our Oil and Natural Gas Subsidiary Pertra" in Item 5 of this annual report and our continued production of the Varg field using *Petrojarl Varg* as described in more detail above under "— Our Production Segment — *Petrojarl Varg.*"

Other Factors Related to Our Business

Our Research and Product Development

We desire to be an industry leader in those oilfield service markets in which our advanced technologies and services may be used. We are committed to providing our customers with innovative services that help to lower the costs of finding and producing oil and natural gas. As a result, we incur research and development costs in an attempt to keep our key assets and services at the forefront of engineering and technical advances. For information regarding our research and development expenditures, please see our consolidated statements of operations in Item 18 of this annual report.

Some of the highlights from our research and development activities in 2005 include:

- development of fiber optic sensor technology for use in reservoir monitoring;
- development of software to construct 3D velocity models;
- development of software to improve the quality of acquired data; and
- improvements to our Cube Manager data processing package.

Intellectual Property

Our patents, trademarks, service marks, copyrights and licenses protect our proprietary technology, including our Ramform seismic vessels and HD3D[SM] seismic solution software. Our intellectual property rights collectively represent a material asset to our business. However, no single patent, trademark, copyright, license or piece of technical information is of material importance to our business when taken as a whole. As of December 31, 2005, we held 160 patents under the laws of the United States, the United Kingdom and Norway. The duration of these patents varies from 3 to 18 years, depending upon the date filed and the duration of protection granted by each country. For more information relating to the risks associated with our dependence upon proprietary technology, see "Key Information — Risk Factors — Risk Factors Relating to Our Business Operations Generally — Our results of operations depend in part upon our ability to protect our proprietary technology" in Item 3 of this annual report.

Seasonality

We incorporate by reference in response to this item the information in "Operating and Financial Review and Prospects — Seasonality" in Item 5 of this annual report.

Operating Conditions and Insurance

Our operations often are conducted under extreme weather and other hazardous conditions. These operations are subject to risks of injury to personnel and loss of equipment. We have safety compliance programs staffed by full-time professional employees and a program for developing, implementing and managing our responsibility for the health and safety of our employees and the environments in which we operate. Systems for reporting and tracking the occupational health of our employees are in place in our business units. Company-wide initiatives focus on the further development of our environmental management systems. All our FPSO units and associated shuttle tankers are ISO 14001 certified (environmental certification). We consider each employee to be a vital contributor to health, safety and environment in our company, and we are fully committed to our health, safety and environment program.

Since 1994 we have operated our own captive re-insurance company that provides insurance for our seismic equipment, including marine acquisition vessels and equipment, onshore equipment, data processing and information technology hardware and software, and some of our production equipment including FPSOs and shuttle tankers. As part of this insurance, all of our seismic vessels, shuttle tankers and FPSOs have a level of coverage against war and terrorism risks that is customary for our industry. We do not generally maintain such insurance for our land-based assets because we do not believe such insurance is cost effective. As noted below, this insurance is subject to deductibles and limits of coverage and is supplemented by commercial reinsurance arrangements with creditworthy re-insurers.

We obtain a substantial portion of our casualty insurance through this wholly owned captive re-insurance company. As of December 31, 2005, we retain risk through this captive company of $4.5 million for each accident, with a maximum risk retention of $7.2 million per year, in excess of underlying deductibles. Our various operating companies have a deductible per occurrence when obtaining this casualty insurance from the captive company, ranging from $125,000 per accident for our seismic vessels, up to $200,000 per accident for our streamers and $750,000 per accident for our FPSOs.

Governmental Regulation

In various areas of the world, we are required to obtain and we have licenses to acquire multi-client seismic data. Licensing and permitting requirements vary widely. We believe that we have complied in all material respects with the licensing and permitting requirements relating to our acquisition of multi-client data.

Our operations are also affected by the exploration and production licensing requirements of various governmental authorities. The timing and extent of licensing of areas for exploration and production activities influence the level of seismic activity within a particular country. Prospective licensees often purchase multi-client seismic data prior to the award of licenses. Following a license award, license holders will generally acquire seismic data for the newly licensed areas if they have not previously obtained multi-client data. In the North Sea, the governments of Norway and the United Kingdom generally hold licensing rounds for exploration and production every year. In the Gulf of Mexico, licensing of blocks for exploration and production are held twice each year, once offshore Texas and once offshore Louisiana. In Brazil, a license round has occurred each year during the last few years. In other areas of the world the timing and extent of these licensing rounds might be more irregular, and the licenses awarded may be subject to resolution of border disputes. The length of the actual license to explore for oil and natural gas varies from region to region and is subject to governmental regulation.

Additionally, our operations are affected by a variety of other laws and regulations, including laws and regulations relating to:

- permitting or licensing agreements for oil and natural gas exploration, development and production activities;
- exports and imports;
- currency;
- taxes;
- occupational health and safety; and
- the protection of the environment.

Our operations are subject to a variety of laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments issue rules and regulations to implement and enforce such laws that are often complex and costly to comply with and that can carry substantial penalties or fines for failure to comply. Under these laws and regulations, we may be liable for remediation or removal costs, damages and other costs associated with releases of hazardous materials including oil into the environment.

We believe that we are currently in compliance in all material respects with the requirements of environmental, export/import and occupational health and safety laws and regulations. Please read "Key Information — Risk Factors — Risk Factors Relating to Our Business Operations Generally — Unpredictable changes in governmental regulations could increase our operating costs and reduce demand for our services" in Item 3 of this annual report.

Capital Expenditures

We incorporate by reference in response to this item the information in "Operating and Financial Review and Prospects — Liquidity and Capital Resources — Capital Requirements and Commitments" in Item 5 and note 27 of the notes to our consolidated financial statements in Item 18 of this annual report, which, among other things, provide information on the nature and geographic distribution of our capital expenditures.

Geographic Mix of Operations and Segment Information

We incorporate by reference in response to this item the information regarding the geographic mix of our operations and segments, including revenue breakdowns, in note 27 of the notes to our consolidated financial statements in Item 18 of this annual report.

Organizational Structure

We provide in the following table a list of our subsidiaries and affiliated companies as of March 23, 2006.

Name	Jurisdiction	Ownership
PGS Shipping AS	Norway	100%
Oslo Seismic Services Ltd.	Isle of Man	100%
PGS Geophysical AS	Norway	100%
PGS Production AS	Norway	100%
Multiklient Invest AS	Norway	100%
Petroleum Geo-Services, Inc.	United States	100%
Petroleum Geo-Services (UK) Ltd.	United Kingdom	100%
Seahouse Insurance Ltd.	Bermuda	100%

Name	Jurisdiction	Ownership
PGS Mexicana SA de CV	Mexico	100%
Dalmorneftegeofizika PGS AS	Norway	49%
Geo Explorer AS	Norway	50%
Baro Mekaniske Verksted AS	Norway	10%
Calibre Seismic Company	United States	50%
PGS Capital, Inc.	United States	100%
Diamond Geophysical Services Company	United States	100%
PGS Exploration (Nigeria) Ltd.	Nigeria	100%
PGS Data Processing Middle East SAE	Egypt	100%
PGS Data Processing, Inc.	United States	100%
Petroleum Geo-Services Asia Pacific Pte. Ltd	Singapore	100%
PGS Australia Pty. Ltd.	Australia	100%
Atlantis (UK) Ltd.	United Kingdom	100%
PGS Egypt for Petroleum Services	Egypt	100%
Hara Skip AS	Norway	100%
PGS Exploration, SDN BHD	Malaysia	100%
PGS Exploration, Inc.	United States	100%
PGS Exploration Pty. Ltd.	Australia	100%
PGS Ocean Bottom Seismic, Inc.	United States	100%
PGS Exploration (UK) Ltd.	United Kingdom	100%
PGS Floating Production (UK) Ltd.	United Kingdom	100%
PGS Pension Trustee Ltd.	United Kingdom	100%
PGS Reservoir (UK) Ltd.	United Kingdom	100%
Atlantic Explorer Ltd.	Isle of Man	50%
Oslo Seismic Services Inc.	United States	100%
Oslo Explorer Plc	Isle of Man	100%
Oslo Challenger Plc	Isle of Man	100%
PGS Shipping (Isle of Man) Ltd.	Isle of Man	100%
PGS Onshore, Inc.	United States	100%
PGS Onshore (Canada), Inc.	Canada	100%
PGS Americas, Inc.	United States	100%
Seismic Energy Holding, Inc.	United States	100%
PGS Caspian AS	Norway	100%
PGS Multi-Client Seismic Ltd.	Jersey	100%
PGS Marine Services (Isle of Man) Ltd.	Isle of Man	100%
Golar-Nor Offshore AS	Norway	100%
Golar-Nor Offshore (UK) Ltd.	United Kingdom	100%
K/S Petrojarl I AS	Norway	98.5%
Golar-Nor (UK) Ltd.	United Kingdom	100%
Deep Gulf LLC	United States	50.1%
PGS Nopec (UK) Ltd.	United Kingdom	100%
PGS Nominees Ltd.	United Kingdom	100%
Petrojarl IV DA	Norway	99.25%
SOH, Inc.	United States	100%

Name	Jurisdiction	Ownership
PT PGS Nusantara	Indonesia	100%
PGS Processing (Angola) Ltd.	United Kingdom	100%
Seismic Exploration (Canada) Ltd.	United Kingdom	100%
PGS Ikdam Ltd.	United Kingdom	100%
Sakhalin Petroleum Plc	Cyprus	100%
Ikdam Production, SA	France	40%
PGS Investigacào Petrolifera Limitada	Brazil	99%
Sea Lion Exploration Ltd.	Bahamas	100%
PGS Administración y Servicios S.A. de C.V.	Mexico	100%
PGS Servicios C.A	Venezuela	100%
PGS Venezuela de C.A	Venezuela	100%
PGS Overseas AS	Norway	100%
PGS Suporte Logistico e Servicos Ltda.	Brazil	100%
PGS Finance, Inc.	United States	100%
Valiant International Petroleum Ltd.	United Kingdom	24.6%
PGS Japan K.K	Japan	100%
PGS Petrojarl Varg AS	Norway	100%
PGS Tanker AS	Norway	100%
PGS Ramform Banff Ltd.	United Kingdom	100%
PGS Ramform Banff AS	Norway	100%

Leased Premises

Our principal offices are at Lysaker, Norway in leased premises. We also maintain leased premises in other cities in Norway, the United States, Angola, Azerbaijan, Australia, Bangladesh, Bolivia, Brazil, Canada, China, Ecuador, Egypt, England, France, Indonesia, Kazakhstan, Libya, Malaysia, Mexico, Nigeria, Russia, Scotland, Singapore, the United Arab Emirates and Venezuela. We believe that all leased properties are well maintained and are suitable for our present activities.

ITEM 4A. *Unresolved Staff Comments*

None.

ITEM 5. *Operating and Financial Review and Prospects*

You should read the discussion under this caption in combination with consolidated financial statements and the related notes in Item 18 of this annual report and "Key Information — Selected Financial Data" in Item 3 of this annual report. This discussion is based upon, and the consolidated financial statements included in Item 18 of this annual report have been prepared in accordance with, United States generally accepted accounting principles. The following information contains forward-looking statements. You should refer to the section in this annual report captioned "Forward-Looking Statements" for cautionary statements relating to forward-looking statements.

Overview

We are a technologically focused oilfield service company principally involved in providing geophysical services worldwide and providing floating production services in the North Sea. Globally, we provide a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, we own and operate four harsh environment floating production, storage and offloading vessels ("FPSOs").

In 2005, we managed our business in three segments as follows:

- *Marine Geophysical*, which consists of streamer seismic data acquisition, marine multi-client library and data processing;
- *Onshore*, which consists of all seismic operations on land and in shallow water and transition zones, including our onshore multi-client library; and
- *Production*, which owns and operates four harsh environment FPSOs in the North Sea.

We discuss below our results of operations based on the three remaining business segments and Pertra as a separate business segment through February 2005. We manage our Marine Geophysical segment from Lysaker, Norway, our Onshore segment from Houston, Texas, and our Production segment from Trondheim, Norway.

On March 1, 2005, we sold Pertra AS, a small oil and natural gas company that we managed as a separate segment, to Talisman Energy (UK) Ltd. ("Talisman") as described in more detail below. Pertra was included in our reported numbers through February 2005. Pertra owned 70% of and was operator for Production License 038 ("PL038") on the Norwegian Continental Shelf ("NCS") and also owned participating interests in six additional NCS licenses without production. Pertra has been renamed Talisman Production Norge AS.

On March 27, 2006, our Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate our geophysical and production businesses and calling an extraordinary general meeting of our shareholders to vote on the transaction, to be held on April 28, 2006. If the transaction is approved by our shareholders and completed, our shares would be split into shares of two independently listed companies. For more information relating to our possible separation, see "— Proposed Separation of the Geophysical and Production Businesses" in Item 4 of this annual report. The effects on the consolidated financial statement of the proposed demerger are described separately. For a more comprehensive discussion of our history and development, including our business segments and our strategic focus, please read "Information on the Company" in Item 4 of this annual report.

Effects of the Demerger on Consolidated Financial Statements

The Production business will be presented as held for sale (discontinued operations) in the consolidated financial statements from the date of board approval of the demerger plan. In addition, historical financial information of the Pertra operations will be presented as discontinued from the same date, as the continued business relations with Pertra (now Talisman Production Norge AS) related to *Petrojarl Varg* will be discontinued with the demerger of the Production business.

2005 Refinancing

In 2005, we (a) repaid $250 million of our unsecured 8% Senior Notes due 2006 and (b) refinanced $741 million of the $746 million of unsecured 10% Senior Notes due 2010 and our $110 million secured credit facility. The 8% Senior Notes and the 10% Senior Notes were issued in our 2003 financial restructuring. We redeemed $175 million of the 8% Senior Notes at 102% of par value in April 2005 and the remaining $75 million of such notes at 101% of par value in November 2005.

In December 2005, we completed a tender offer and consent solicitation for our $746 million 10% Senior Notes due 2010. As a result, we retired approximately $741.3 million aggregate principal amount of the notes at a price of 113.64% of par value. Debt redemption and refinancing costs totaled $107.3 million (including a $0.4 million write-off of deferred debt issue costs) and $9.9 million in capitalized deferred debt issue costs.

As part of the refinancing, we established a $1 billion senior secured credit facility consisting of a seven-year $850 million term loan and a five-year $150 million revolving credit facility. The new revolving credit facility replaced our previous $110 million secured credit facility. For additional information about our new credit facility, please read "— Liquidity and Capital Resources — Sources of Liquidity — Capital Resources" below.

Sale of Our Oil and Natural Gas Subsidiary Pertra

On March 1, 2005, we sold our wholly owned subsidiary Pertra AS to Talisman for an initial sales price of approximately $155 million, which resulted in a gain of $149.8 million, including the $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg* as described below.

As a part of the agreement with Talisman, we are entitled to an additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006 we received $8.1 million, representing the 2005 portion of the contingent consideration, and recognized that amount as an additional gain from the 2005 sale. This amount was recognized as an additional gain from the sale in 2005.

We also granted an option enabling Talisman to change the termination clause with respect to PL038. The option expired on February 1, 2006 without being exercised. *Petrojarl Varg* will therefore continue to produce the Varg field for a fixed base day rate of $90,000 and a variable rate of $6.30 per barrel produced. We are entitled in some cases to terminate the agreement if the production of the Varg field falls below 15,700 barrels per day. Based on the current production profile of the Varg field, *Petrojarl Varg* could become available for redeployment on a new field in 2008.

2003 Financial Restructuring

In 2003, we implemented a financial restructuring through a reorganization under Chapter 11 of the U.S. Bankruptcy Code. The reorganization became effective and was substantially consummated on November 5, 2003. Under the reorganization plan, $2,140 million of our senior unsecured debt was cancelled, and the associated creditors received the following:

- $746 million of unsecured 10% Senior Notes due 2010;
- $250 million of unsecured 8% Senior Notes due 2006;
- $4.8 million of an eight-year unsecured senior term loan facility (which the Company fully repaid in May 2004);
- 91% of our new ordinary shares as constituted immediately post restructuring, with an immediate reduction of this shareholding to 61% in a rights offering of 30% of the new ordinary shares to the pre-restructuring shareholders for $85 million, or $14.17 per share; and
- $40.6 million of cash, of which $17.9 million was distributed in December 2003 and the remainder in May 2004.

Under the reorganization plan,

- our pre-restructuring share capital was cancelled and 20,000,000 new ordinary shares, par value NOK 30 per share, were issued;
- the pre-restructuring shareholders received 4%, or 800,000, of the new ordinary shares and the right to acquire 30%, or 6,000,000, of the new ordinary shares for $85 million ($14.17 per share) in the rights offering;
- pre-restructuring owners of $144 million of trust preferred securities received 5%, or 1,000,000, of the new ordinary shares; and
- the principal amount of our interest-bearing debt and capital lease obligations was reduced by approximately $1,283 million to approximately $1,210 million immediately after the restructuring.

2003 Fresh Start Reporting and Changes in Accounting Policies

In connection with our emergence from Chapter 11 reorganization, we adopted "fresh start" reporting for financial statement purposes, effective November 1, 2003, in accordance with SOP 90-7. Under SOP 90-7, we adjusted the recorded value of our assets and liabilities to reflect their fair market value as of the date we emerged from Chapter 11 reorganization.

In connection with our adoption of fresh start accounting, we reviewed our accounting policies with a view toward creating new policies that are less complex, more transparent and better reflect current operations. The most significant changes in our accounting policies were:

- expenditures incurred in connection with steaming and mobilization are expensed as incurred. Onsite project costs such as positioning, deploying and retrieving equipment at the beginning and end of a project are considered mobilization or demobilization costs and are expensed as incurred, unless the project relates to the building of the multi-client data library, in which case such costs are included in the costs of the multi-client survey. Such expenses were previously recognized as part of contract costs or multi-client project costs as appropriate, and as such would not have been fully expensed immediately,

- the successful efforts method of accounting for oil and natural gas assets was adopted,

- we made certain changes to our amortization policy for our multi-client library, including an increase in minimum amortization by reducing the maximum amortization period from eight to five years after completion of a survey,

- depreciable lives of Ramform seismic acquisition vessels and FPSOs, other than the *Petrojarl I*, were reduced from 30 to 25 years.

Please refer to note 2 of our consolidated financial statements included in Item 18 of this annual report for disclosure of our significant accounting policies, including those policies that changed under fresh-start. Please refer to note 3 for disclosure of the fresh-start adjustments.

Critical Accounting Policies and Estimates

We discuss below our operating results and financial condition based on our consolidated financial statements, which are prepared in accordance with U.S. GAAP. In order to prepare these financial statements, we must make estimates and assumptions that affect the reported amount of assets and liabilities, our disclosure of contingent assets and liabilities and the amounts of reported revenues and expenses. We evaluate our estimates and assumptions from time to time and may employ outside experts to assist in our evaluations. We believe that our estimates and assumptions are reasonable, but we acknowledge that actual results may vary from what we have estimated or assumed. Our significant accounting policies are described in note 2 to the consolidated financial statements included in Item 18 of this annual report.

We list and summarize in greater detail below those accounting policies that we believe to be the most critical in the preparation and evaluation of our financial statements and that involve the use of assumptions and estimates that require a higher degree of judgment and complexity. As a result, our reported assets, liabilities, revenues and expenses could be materially affected if the assumptions and estimates we make were changed significantly, and our actual financial position, results of operations, cash flows and future developments may differ materially from the assumptions and estimates we have made. Our critical accounting policies and related estimates for the periods discussed below relate to:

- revenue recognition;

- multi-client data library, including cost capitalization, sales, amortization and impairment;

- long-lived assets, particularly impairment and depreciation, depletion and amortization;

- deferred tax assets;

- fresh start reporting; and

- oil and natural gas accounting, including capitalization, amortization and impairment.

Revenue Recognition

We recognize revenue on our contract sales of data and on our other geophysical services as we perform the services and are able to charge the customer for these services. Because of the nature of the geophysical services business, we incur and recognize costs from time to time prior to the time revenues can be recognized. As a result, a non-symmetrical matching of revenues and expenses may result in variability of results of operations between accounting periods. We generally recognize revenue from our floating production services in two components. First, we recognize tariff based revenues, based on the number of barrels produced, as production occurs. Second, we recognize day rate revenues over the passage of time. We recognize revenues from the production and sale of oil and natural gas when the production is delivered and ownership has passed to the customer. After the sale of Pertra in March 2005, revenues from the production and sale of oil and natural gas are not material.

Sales of data from our multi-client library generally fall into one of three categories.

- Late sales — we grant a license to the customer for a specified portion of the library.
- Volume sales agreements — we grant a license or licenses to a specified number of blocks in a defined geographical area so that the customer can select and access the specific blocks over a period of time.
- Pre-funding arrangements — we obtain funding from a limited number of customers before a seismic acquisition project commences. In return for the pre-funding, the customer typically gains the ability to direct or influence the project specifications, to access data as it is being acquired and to pay discounted prices.

We recognize revenue:

- from late sales when the customer executes a valid license agreement and has been granted access to the library and collection is reasonably assured;
- from volume sales agreements ratably based on the total revenue and volume of data specified in the agreement as the customer executes licenses for specific blocks and has been granted access to the data; and
- from pre-funding arrangements as the data is acquired, generally based on physical progress, on a proportional performance basis.

Multi-Client Data Library

We discuss revenue recognition relating to our multi-client library above under "— Revenue Recognition."

We capitalize as an asset the costs associated with acquiring and processing multi-client data. We base our amortization of the multi-client data library on the sales forecast method. Under this method, we amortize the cost of a particular survey contained in the library based on the ratio between the cost of the survey and the total forecasted sales of data for such survey. In applying this method following our adoption of fresh start reporting, we categorize surveys into three amortization categories with amortization rates of 90%, 75% or 60% of sales amounts. Each category will include surveys where the remaining unamortized cost as a percentage of remaining forecasted sales is less than or equal to the amortization rate applicable to each category. We have also established maximum book value criteria for the library projects based on a five-year life for marine and onshore projects and a three-year life for all derivative processed projects. The maximum book value for each project at year-end is the total cost of the project less accumulated straight-line minimum amortization. Prior to our adoption of fresh start reporting, we amortized our multi-client data library based on the ratio of actual sales to expected sales with a minimum amortization based on five to eight year lives.

We periodically evaluate the projects in the multi-client library for impairment. Effective January 1, 2004, we classify as amortization expense in our consolidated statements of operations write-downs of individual multi-client surveys that are based on changes in project specific expectations and that are not individually material. We expect this additional, non-sales related, amortization expense to occur regularly because we evaluate projects individually. We classify as impairment in our consolidated statements of operations write-downs related to significant changes in estimates affecting a larger part of our multi-client library where the effects are material. Prior to 2004 we classified as impairment expense all write-downs of multi-client library.

In determining the ordinary amortization rates applied to, and fair value of, our multi-client data library, we consider expected future multi-client sales, sales costs, market developments and past experience. Our sales expectations include consideration of geographic locations, prospects, political risk, exploration license periods and general economic conditions. These sales expectations are highly subjective, cover extended periods of time and are dependent on a number of factors that we do not control. Accordingly, these expectations could differ significantly from year to year. Our ability to recover costs included in the multi-client data library through sales of the data depends upon continued demand for the data and the absence of technological or regulatory changes or other developments that would render the data obsolete or reduce its value.

Through 2003, the sales expectations for our multi-client library declined significantly, reflecting a weakening of the market for multi-client data. As a result, our multi-client library amortization rates increased over time and we recognized an impairment of the multi-client data library of $90 million for the Predecessor for the ten months ended October 31, 2003. In 2004 and 2005, we had higher total sales than we expected. Although the total sales expectations for many of the surveys have increased, expectations for certain individual surveys have decreased or been delayed, resulting in additional non-sales related amortization on those surveys. Because we apply our impairment tests and calculate our minimum amortization on a survey-by-survey basis, and due to the inherent uncertainty of sales forecasts, we are likely to have additional non-sales related amortization in the future.

Due to our adoption of fresh-start reporting, the book value of the portion of our multi-client library that was recognized in the fresh-start balance sheet will be reduced if and when we realize pre-fresh-start tax assets. Future amortization costs will be reduced accordingly. For additional information, please see "— Deferred Tax Assets" below and Note 21 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Oil and Natural Gas Accounting

Following our adoption of fresh-start reporting, we used the successful efforts method of accounting for oil and natural gas properties. Under this method, all costs of acquiring unproved oil and natural gas properties and drilling and equipping exploration wells are capitalized pending determination of whether the properties have proved reserves. If an exploration well is determined not to have commercial quantities of reserves, the drilling and equipment costs for the well are expensed and classified as exploration costs at that time. All development drilling and equipment costs are capitalized. Capitalized costs of proved properties are amortized on a property-by-property basis using the unit-of-production method whereby the ratio of annual production to beginning of period proved oil and natural gas reserves is applied to the remaining net book value of such properties. Geological and geophysical costs are expensed as incurred and presented as exploration costs.

The estimates of proved oil and natural gas reserves as of December 31, 2004 and 2003 were prepared by our engineers in accordance with guidelines established by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The estimates were reviewed by an independent reservoir engineering consultant. Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Both in 2003 and 2004, we had substantial increases of reserves caused by new extensions and discoveries. In addition, we had a fairly substantial increase in 2003 caused by a revision of previous estimates. For additional information about these estimates, please read note 30 of the consolidated financial statements included in Item 18 of this annual report.

Prior to our adoption of fresh start reporting, we used the full cost method of accounting for oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Costs are accumulated on a country-by-country basis. Under this method, capitalized costs are amortized using the unit-of-production method on a country-by-country basis. Unevaluated properties are excluded from the amortization base. Future development costs and dismantlement and abandonment costs are included in the amortizable cost base. In accordance with SEC guidelines, the cost bases of proved oil and natural gas properties accounted for under the full cost method are limited, on a country-by-country basis, to the estimated future net cash flows from proved oil and natural gas reserves using prices and other economic conditions in effect at the end of the reporting period, discounted at 10%, net of related taxes. If the capitalized cost of proved oil and natural gas properties exceeds this limit, the excess is charged to expense as additional depletion, depreciation and amortization.

We sold our oil and natural gas subsidiary Pertra to Talisman in March 2005 as described in "— Sale of our Oil and Natural Gas Subsidiary Pertra" above. For additional information about our oil and natural gas accounting, please read note 2 of the consolidated financial statements included in Item 18 of this annual report.

Accounting for Long-Lived Assets

We review long-lived assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the total of the undiscounted future cash flows is less than the carrying amount of the asset or group of assets, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the asset or group of assets. We assess for possible impairment long-lived assets, such as multi-client data library, property and equipment, and proved oil and natural gas assets accounted for under the successful efforts method, upon the occurrence of a triggering event. Events that can trigger assessments for possible impairments include, but are not limited to (a) significant decreases in the market value of an asset, (b) significant changes in the extent or manner of use of an asset, (c) a physical change in the asset, (d) a reduction of proved oil and natural gas reserves based on field performance and (e) a significant decrease in the price of oil or natural gas. We assess for impairment unproved oil and gas properties in accordance with the guidelines of SFAS No. 19. Prior to the adoption of fresh-start reporting, we assessed for impairment oil and natural gas assets in accordance with the full cost accounting guidelines as described under "Oil and Natural Gas Accounting" above.

Estimating undiscounted future cash flows requires us to make judgments about long-term forecasts of future revenues and costs related to the assets subject to review. These forecasts are uncertain as they require assumptions about demand for our products and services, future market conditions and future technological developments. Significant and unanticipated changes in these assumptions could require a provision for impairment in a future period. Given the nature of these evaluations and their application to specific assets and specific times, it is not possible to reasonably quantify the impact of changes in these assumptions.

Through 2003, the future cash flow expectations for most of our assets declined in line with difficult markets. As a result, we experienced substantial impairments both in 2002 and in 2003. In addition, we recognized a substantial reduction in asset values when we adopted fresh start accounting in November 2003. In line with a strengthening of the markets, the future cash flow expectations have generally increased subsequent to 2003, although expectations for certain individual assets have decreased. However, we have not identified any impairment needs for individual assets in 2004 and 2005, except for the impairments recorded as a consequence of the decision to discontinue our four component seafloor operations in 2005 of $4.6 million.

Deferred Tax Assets

At December 31, 2005, we had a total of $623 million of deferred tax assets (net of deferred tax liabilities) in different jurisdictions, predominantly in Norway and the UK. At adoption of fresh-start reporting on November 1, 2003 and at December 31, 2004, we established valuation allowances for all of our deferred tax assets, with the exception of tax assets relating to Pertra. A valuation allowance, by tax jurisdiction, is established when it is more likely than not that all or some portion of the deferred tax assets will not be realized. The valuation allowance is periodically adjusted based upon the available evidence. During 2005, we concluded that certain valuation allowances were no longer necessary as available evidence, including recent profits and estimates of projected near term future taxable income, supported a more likely than not conclusion that the related deferred tax assets would be realized. As a result, in 2005 we released a portion of our valuation allowance, resulting in the recognition of a deferred tax asset of $20 million on the consolidated balance sheets at December 31, 2005.

The estimates of projected near term future taxable income are based on a variety of factors and assumptions, many of which are subjective and are outside of our control. Accordingly, these estimates could differ significantly from year to year, and we might end up realizing more or less of the deferred tax assets than we have recognized on the balance sheet.

If and when we realize the benefits of deferred tax assets, for which we established a valuation allowance at the adoption of fresh-start reporting, the positive effect does not flow through the consolidated statement of operations as a tax benefit, but is rather (as required under SOP 90-7) recorded as a reduction of the carrying value of long-term intangible assets existing at adoption of fresh-start reporting, until the value of such assets is reduced to zero. If there are benefits of deferred tax assets to be realized after those intangible assets have been reduced to zero, the benefits would be credited to shareholders' equity. As a result of realization of such deferred tax assets in 2005, we reduced the carrying values of the multi-client library by $25.3 million and other intangible assets by $1.8 million. Of the total valuation allowance as of December 31, 2005, $390.0 million relates to pre-reorganization amounts and will only affect net income through reduction of amortization expense for intangible assets. For additional information about how we account for deferred tax assets, please see Note 2 and Note 21 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Fresh-Start Reporting

We adopted fresh-start reporting upon our emergence from Chapter 11 in accordance with SOP 90-7. Accordingly, all assets and liabilities were adjusted to reflect their reorganization value as of November 1, 2003, which approximates fair value at the date of reorganization. We engaged independent financial advisors to assist in the determination of the reorganization value of the combined entity and for most of the individual assets and liabilities. Assets and liabilities were valued based on a combination of the cost, income and market approach. We also considered technical, functional and economic obsolescence. Please see "— 2003 Fresh-Start Reporting and Changes in Accounting Policy" above.

Similar to the estimates made for long-lived assets as described above, the estimates of fair value made for purposes of fresh start reporting required judgments regarding long-term forecasts of future revenues and costs related to all significant assets and liabilities. These forecasts are uncertain in that they require assumptions about demand for our products and services, future market conditions and technological developments. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period.

We have indemnified the lessors in the UK leases for, among other things, the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities ("Tax Indemnities"). In connection with the adoption of fresh-start reporting in November 2003, we recorded a liability of 16.7 million British pounds (approximately $28.3 million) relating to the Tax Indemnities. We release applicable portions of this liability if and when the UK Inland Revenue accepts the lessors' claims for capital allowances under each lease. In 2005, we released 9.4 million British pounds (approximately $17.2 million) of the liability. The remaining accrued liability as of December 31, 2005 is 7.3 million British pounds (approximately $12.7 million) and relates to the *Petrojarl Foinaven* lease, where an issue relating to the length of asset life remains. For additional information about our UK leases, please read "— Liquidity and Capital Resources — UK Leases" below.

Seasonality

Our Marine Geophysical segment experiences seasonality as a result of weather-related factors. Weather conditions in the North Sea generally prevent the full operation of seismic crews and vessels in the winter season and, due to vessel relocation, generally adversely impact our first and fourth quarter results and, to a lesser extent, our second quarter results. Storm seasons in the tropics can also affect our operations when we have crews in the Gulf of Mexico or tropical Asia. During these periods, we generally relocate our seismic vessels to areas with more favorable weather conditions to conduct seismic activities, or we conduct repairs and maintenance. On the other hand, our fourth quarter revenue has historically been positively affected by end-of-year sales of multi-client data to oil and natural gas companies. In addition, timing of licensing activities and oil and natural gas lease sales may significantly affect quarterly operating results.

Our Onshore segment can also be affected by weather and seasons, depending on where we deploy our crews at a particular time. Our Production segment generally does not experience material seasonal effects, other than normal maintenance and refurbishment activities for our FPSO vessels in our Production segment that typically take place during the summer months.

Our results of operations fluctuate from quarter to quarter due to a number of other factors. Oil and natural gas industry capital expenditure budgets and spending patterns influence our results. These budgets are not necessarily spent in equal or progressive increments during the year, with spending patterns affected by individual customer requirements and industry-wide conditions. In addition, under our revenue recognition policy, revenue recognition from data licensing contracts depends, among other things, upon when the customer selects the data. In addition, many of our contract projects are relatively short term. The timing of start-up and completion and crew or vessel movement can significantly affect our results of operations from period to period. As a result, our seismic services revenue does not necessarily flow evenly or progressively during a year or from year to year.

Impact of Foreign Currency Fluctuations

We conduct business in various currencies and are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions in currencies other than the U.S. dollar. For a more complete discussion of the impact of foreign currency fluctuations and the extent to which we hedge this exposure, please see "Quantitative and Qualitative Disclosures About Market Risk — Foreign Currency Exchange Rate Risk" in Item 11 of this annual report.

Results of Operations

Overview

Our results of operations for the years 2005, 2004 and 2003 (Successor and Predecessor) are presented below in an expanded format that shows the primary components of and key drivers affecting our results of operations. Our consolidated statements of operations show separately the ten month period ended October 31, 2003 (Predecessor) and the two month period ended December 31, 2003 (Successor) as we emerged from Chapter 11 bankruptcy proceedings on November 5, 2003 and adopted fresh-start reporting effective as of November 1, 2003. As indicated in the discussion of our results for 2003 below, Successor and Predecessor are in some areas combined for purposes of the discussion. Successor financial statements are prepared on the basis of fresh start reporting from November 1, 2003 and include changes in the carrying value of assets and liabilities and changes to certain accounting policies.

In addition, the results of operations discussed below exclude the results from our Atlantis oil and natural gas subsidiary and our Tigress software subsidiary, both of which were sold in 2003 and are presented as discontinued operations in our consolidated financial statements included in Item 18 of this annual report. The results of operations discussed below include the results for Pertra, our oil and natural gas subsidiary that we sold in March 2005, through February 2005. The *Petrojarl Varg* (Production segment) has provided production services to the operators of PL 038, in which Pertra owned a 70% interest. Accordingly, for the period during which we owned Pertra, 70% of the associated revenues from the *Petrojarl Varg* have been eliminated as inter-segment revenues. Effective from the sale of Pertra, we report this portion of the revenues from the *Petrojarl Varg* as external revenues. As a result, the revenues of Production included in our consolidated statement of operations have increased.

We discuss below our results of operations based on the three remaining business segments — Marine Geophysical, Onshore and Production — and Pertra as a separate business segment through February 2005. We operate our Marine Geophysical and Onshore businesses globally and generate revenues primarily through contract acquisition sales and multi-client sales (pre-funding and late sales). Our Production segment generates revenues from contract production activities in the Norwegian and U.K. sectors of the North Sea. Pertra generated oil production revenues from its 70% interest in PL 038 in the Norwegian Sector of the North Sea.

Revenues

The table below presents our mix of revenues for each of the three years by business segment.

	Successor Company			Predecessor Company	Combined
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,	Twelve Months Ended December 31,
	2005	2004	2003	2003	2003
	(In thousands of dollars)				
Marine Geophysical					
Contract	$ 424,192	$ 297,749	$ 48,273	$302,451	$ 350,724
Multi-client pre-funding	40,006	30,535	6,510	43,187	49,697
Multi-client late sales	218,781	203,397	36,786	123,435	160,221
Other	41,703	39,124	7,813	31,040	38,853
	724,682	570,805	99,382	500,113	599,495
Onshore					
Contract	122,415	110,288	18,442	106,324	124,766
Multi-client pre-funding	16,148	12,761	1,807	14,636	16,443
Multi-client late sales	13,976	10,112	1,210	8,005	9,215
	152,539	133,161	21,459	128,965	150,424
Production					
Petrojarl I	53,394	61,303	11,086	58,529	69,615
Petrojarl Foinaven	89,191	96,595	18,726	93,373	112,099
Ramform Banff	46,483	51,509	6,572	38,616	45,188
Petrojarl Varg	89,920	87,133	8,604	59,191	67,795
Other	1,689	1,662	241	349	590
	280,677	298,202	45,229	250,058	295,287
Other/elimination	1,686	(56,834)	(3,243)	(29,369)	(32,612)
Total revenues (services)	1,159,584	945,334	162,827	849,767	1,012,594
Revenues (products) — Pertra	36,742	184,134	9,544	112,097	121,641
Total revenues	$1,196,326	$1,129,468	$172,371	$961,864	$1,134,235

Our revenues for 2005 increased by $66.8 million as compared with 2004. Marine Geophysical increased by $153.9 million, while Onshore revenues increased by $19.3 million. These increases were offset by a reduction of revenues from Pertra, which was sold in March 2005, of $147.4 million, offset by a decrease in elimination of inter-segment revenues of $58.5 million, mainly caused by 70% of the revenues from *Petrojarl Varg* being reported as external from March 2005 as a result of the sale of Pertra. Total Production revenues decreased $17.5 million. Revenues for 2004 decreased $4.7 million as compared with combined 2003 revenues for Predecessor and Successor. Pertra revenues increased by $62.5 million, but this increase was more than offset by a decrease of revenues in Marine Geophysical ($28.7 million) and Onshore ($17.2 million) and higher elimination of inter-segment revenues as described below.

Marine Geophysical — 2005 vs. 2004. Marine Geophysical 2005 revenues increased by $153.9 million (27%) as compared with 2004. Revenues from contract seismic acquisition increased by $126.5 million (42%), primarily as a result of improved pricing, better contractual terms and general improvement of operational efficiency in 2005. In 2004, in addition to weaker pricing, revenues were negatively affected by significant operating disturbances during completion of a large turnkey project offshore India in the second quarter. Revenues from multi-client late sales increased by $15.4 million (8%). In 2005, we increased our investment in multi-client data, and revenues from multi-client pre-funding increased by $9.5 million (31%). Pre-funding as a percentage of cash investments in multi-client data decreased to 87% in 2005 compared to 99% in 2004. We had a fairly consistent allocation of total 3D streamer capacity (measured by active streamer months) with approximately 91% contract and 9% multi-client in 2005, compared to 88% and 12%, respectively, in 2004.

Marine Geophysical — 2004 vs. 2003. Marine Geophysical 2004 revenues decreased by $28.7 million (5%) as compared with 2003 (combined). Revenues from contract seismic acquisition decreased by $53.0 million (15%), primarily due to a close down of our ocean bottom 2C crew in late 2003. Revenues from this crew amounted to $40.5 million in 2003 (combined). In addition, contract revenues were negatively impacted by a weak contract market in the first half of 2004 and significant operating disturbances during completion of a large turnkey project offshore India in the second quarter. Revenues from multi-client late sales increased by $43.2 million (27%), reflecting overall high demand in the second half of 2004. In 2004, we reduced further our acquisition of multi-client data, and revenues from multi-client pre-funding decreased by $19.2 million (39%). Pre-funding as a percentage of cash investments in multi-client data increased to 99% in 2004 compared to 72% in 2003. In 2004, we allocated the total 3D streamer capacity for our seismic fleet between contract and multi-client data acquisition (measured by active streamer months) approximately 88% and 12%, respectively, as compared to approximately 78% and 22%, respectively, in 2003.

Onshore — 2005 vs. 2004. Onshore revenues for 2005 increased by $19.3 million (14%) as compared with 2004. Onshore had higher revenues in the U.S. and Canada both within the contract market and within the multi-client market (where all revenues are generated in the U.S.). Furthermore, the new project in Nigeria caused increasing revenues in the Eastern Hemisphere, offset by a further reduction of the activity level and revenues in Mexico.

Onshore — 2004 vs. 2003. Onshore revenues for 2004 decreased by $17.3 million (11%) as compared with 2003 (combined). Onshore had significant activity in Alaska, Mexico and Saudi Arabia in 2003, but in 2004 Onshore had no activity in Saudi Arabia or Alaska. In addition, activity in Mexico declined at the end of 2004 as we completed one of our two large projects in that region in the third quarter.

Production — 2005 vs. 2004. Production revenues for 2005 decreased $17.5 million (6%) as compared to 2004. *Petrojarl I* revenues declined $7.9 million (13%) and *Petrojarl Foinaven* revenues declined $7.4 million (8%) primarily due to natural field production declines. In addition, production from *Petrojarl Foinaven* was reduced by problems related to oil/water separation and related maintenance slowdown and shutdown. Revenues from *Ramform Banff* decreased by $5.0 million (10%), primarily due to a $3.7 million lump sum modification job for Canadian Natural Resources included in 2004 revenues, while production compensation has been realized at the minimum day rate both in 2004 and 2005. Production levels on *Ramform Banff* have been fairly consistent, just above 10,000 barrels per day, both in 2004 and 2005. Revenues from *Petrojarl Varg* increased by $2.8 million (3%), including inter-segment revenues from Pertra (approximately 70% of *Petrojarl Varg* revenues through February 2005). The increase is due primarily to increased production. Both 2004 and 2005 were negatively affected by a damage to the main production riser on the Varg field that reduced production from November 5, 2004 until March 9, 2005. The compensation structure in the *Petrojarl Varg* production contract was amended, effective May 29, 2004, to a combination of a fixed day rate and a production tariff (as compared to a pure production tariff previously).

Production — 2004 vs. 2003. Production revenues for 2004 increased $2.9 million (1%) as compared to 2003 (combined). *Petrojarl Foinaven* revenues declined $15.5 million (14%) primarily due to a natural field production decline. *Petrojarl I* revenues declined $8.3 million (12%) primarily for the same reason. Further, the production on *Petrojarl I* was shut down from September 12 to October 29, 2004 due to a labor conflict on the NCS, but the revenue impact was limited as we received force majeure compensation during the period. Revenues from *Ramform Banff* increased by $6.3 million (14%), primarily due to a $3.7 million lump sum modification job for Canadian Natural Resources and a new production contract effective January 1, 2004 with a minimum day-rate of $125,000. Revenues from *Petrojarl Varg* increased by $19.3 million (29%), including inter-segment revenues from Pertra (approximately 70% of *Petrojarl Varg* revenues). The increase is due primarily to increased production, despite a shut down for approximately two weeks in October 2004 related to a labor conflict on the NCS and damage to the main production riser on the Varg field that reduced production to approximately 50% of the field's potential from November 5, 2004 through the end of the year.

Elimination of inter-segment revenues. In 2005, elimination of inter-segment revenues (which reduces consolidated revenues) decreased by $60.0 million as compared to 2004 primarily due to reporting 70% of the Production revenues relating to *Petrojarl Varg* as external from March 2005, as a result of the sale of Pertra. Through February 2005, 70% of *Petrojarl Varg* revenues related to Pertra's interest in the Varg field and were eliminated in the consolidated financial statements. These inter-segment revenues, which aggregated $9.1 million, $60.4 million and $45.1 million in 2005, 2004 and 2003 (combined), respectively, are eliminated in our consolidated statement of operations.

Pertra. Pertra revenues for 2005 decreased $147.4 million (80%) as compared with 2004, primarily as a consequence of the sale of Pertra in March, as 2005 includes only two months of revenues from Pertra compared to full year for 2004. Pertra revenues for 2004 increased $62.5 million (51%) as compared with 2003 (combined) primarily due to increased production of oil.

Cost of Sales

The following table shows our cost of sales (products and services), excluding depreciation and amortization, by segment and each segment's cost of sales as a percentage of revenues generated by that segment:

	Successor Company			Predecessor Company	Combined
	Years Ended December 31, 2005	Years Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Twelve Months Ended December 31, 2003
	(In thousands of dollars, except percentage data)				
Marine Geophysical	$373,504	$342,460	$55,903	$248,965	$304,868
% of revenue	51.5%	60.0%	56.3%	49.8%	50.9%
Onshore	$124,334	$ 92,290	$13,043	$ 76,634	$ 89,677
% of revenue	81.5%	69.3%	60.8%	59.4%	59.6%
Production	$184,313	$167,764	$21,208	$133,114	$154,322
% of revenue	65.7%	56.3%	46.9%	53.2%	52.3%
Other	$ 8,613	$ 9,558	$ 900	$ 6,776	$ 7,676
Transfer of cost(1)	(12,418)	(24,160)	3,990	(11,093)	(7,103)
Total cost of sales (services)	$678,346	$587,912	$95,044	$454,396	$549,440
% of revenue	58.5%	62.2%	58.4%	53.5%	54.3%
Cost of sales (products)					
Pertra	$ 28,542	$ 93,035	$ 7,040	$ 61,910	$ 68,950
Elimination(1)	(6,238)	(48,197)	(5,130)	(28,528)	(33,658)
Total cost of sales (products)	$ 22,304	$ 44,838	$ 1,910	$ 33,382	$ 35,292
% of revenue	60.7%	24.3%	20.0%	29.8%	29.0%
Total cost of sales	$700,650	$632,750	$96,954	$487,778	$584,732
% of revenue	58.6%	56.0%	56.2%	50.7%	51.6%

(1) Elimination of inter-segment charter hire related to *Petrojarl Varg* and inter-segment transfers of costs.

Cost of sales (services) — 2005 vs. 2004. Cost of sales (services) increased by $90.4 million in 2005 as compared with 2004 as costs increased in Marine Geophysical, Onshore and Production. The main reasons are increased activity levels in Marine Geophysical and Onshore, general cost increases (in particular fuel prices and payroll) and increased repair and maintenance costs both on the seismic vessels and the FPSOs. Marine Geophysical cost of sales (services) increased $31.0 million, mainly caused by charter of third party 2D vessel capacity in 2005, price increases of fuel and lube and increased repair and maintenance cost, partly offset by an increase in capitalized multi-client cost. The cost of sales as a percentage of revenues for Marine Geophysical decreased to 52% in 2005 compared to 60% in 2004, in line with the substantial increase of revenues. Onshore cost of sales increased $32.0 million, mainly caused by the increased activity level. The cost of sales as a percentage of revenues for Onshore increased to 82% in 2005 compared to 69% in 2004, mainly caused by significant mobilization and start-up costs in Nigeria and Libya where the corresponding expected project revenues, which are recognized based on progress of production, were not all recognized in 2005. Production's cost of sales increased by $16.5 million, primarily due to increased repair and maintenance expenses.

Production's cost of sales includes all of the operating costs, excluding depreciation and amortization, for *Petrojarl Varg*. Through February 2005, 70% of these costs are eliminated from consolidated cost of sales (services) and included in cost of sales (products) and 70% of *Petrojarl Varg* revenues are eliminated from cost of sales (products) representing the 70% interest Pertra had in the Varg field.

Cost of sales (products) — 2005 vs. 2004. Cost of sales (products) decreased by $22.5 million in 2005 as compared with 2004 as 2005 only includes two months of costs for Pertra, as a consequence of the sale of that subsidiary in March 2005, compared to twelve months of costs for 2004.

Eliminations. Total elimination of inter-segment costs (which reduces consolidated operating costs) in 2005 decreased by $57.4 million compared to 2004 primarily due to discontinuing the elimination of 70% of *Petrojarl Varg* charter hire from March 1, 2005.

Cost of sales (services) — 2004 vs. 2003. Cost of sales (services) increased by $38.5 million in 2004 as compared with 2003 (combined) primarily due to reduced multi-client activity in our Marine Geophysical business as we increased our focus in 2004 on contract marine seismic acquisition as compared to 2003. As a result, we reduced costs capitalized as investment in multi-client library by $49.5 million. In addition, cost of sales increased due to general cost increases driven by a weakening of the U.S. dollar against the British pound and the Norwegian kroner (which increases the reported U.S. dollar cost of expenses incurred in those currencies) and increased fuel prices, partially offset by the effect of closing down our ocean bottom 2C crew in late 2003. Production's cost of sales increased by $13.4 million, primarily due to increased materials purchases reimbursed by a customer, a weakening of the U.S. dollar exchange rate (which increases the reported U.S. dollar cost for Production since a significant part of these costs are incurred in British pounds and Norwegian kroner) and increased maintenance expense.

Cost of sales (products) — 2004 vs. 2003. Cost of sales (products) increased by $9.5 million in 2004 as compared with 2003 (combined) as a result of increased Pertra operating costs due primarily to a significant increase in production and increased well intervention costs.

Exploration Costs

Exploration costs were $1.4 million in 2005 compared to $16.3 million in 2004. Exploration costs in 2004 include $11.4 million for the drilling of a dry exploration well in PL038. We incurred exploration costs in our oil and natural gas subsidiary Pertra, which was sold in March 2005. Such costs include costs to drill exploration wells and other costs related to exploration for oil and natural gas, including geological and geophysical services, excluding depreciation and amortization.

Prior to adopting fresh start reporting, we accounted for oil and natural gas assets using the full cost method and all exploration costs were capitalized.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") expenses result primarily from the allocation of capitalized costs over the estimated useful lives of our geophysical seismic vessels and equipment, our FPSO vessels, our seismic and operations computer equipment, leasehold improvements, buildings and other fixtures, and depletion of our oil and gas exploration and production assets (consisting of licenses, tangible and intangible costs of drilling wells and production equipment) that are depleted using a units of production method based on proved oil and gas reserves. DD&A expenses also include the amortization of our multi-client data library, which we refer to as MCDL Amortization, and the amortization of certain intangible assets recognized upon our adoption of fresh start reporting effective as of November 1, 2003.

The following table shows our total DD&A expenses by segment. For our Marine Geophysical and Onshore segments, we have provided separately (1) DD&A expenses excluding MCDL Amortization, or Adjusted DD&A, and (2) MCDL Amortization because we believe that separately disclosing MCDL

Amortization provides users useful information about a key component impacting the results of our geophysical operations.

	Successor Company	Successor Company	Successor Company	Predecessor Company	Combined
	Year Ended December 31, 2005	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Twelve Months Ended December 31, 2003
	(In thousands of dollars)				
Marine Geophysical:					
Adjusted DD&A	$ 54,120	$ 55,277	$ 9,565	$ 59,730	$ 69,295
MCDL amortization	118,229	186,435	29,786	131,485	161,271
DD&A	172,349	241,712	39,351	191,215	230,566
Onshore:					
Adjusted DD&A	16,355	18,677	3,571	14,292	17,863
MCDL amortization	15,310	21,208	2,653	15,133	17,786
DD&A	31,665	39,885	6,224	29,425	35,649
Production:					
DD&A	44,064	44,561	8,112	43,418	51,530
Pertra:					
DD&A	6,710	38,965	743	30,826	31,569
Corporate and other:					
Adjusted DD&A	3,637	2,414	361	4,911	5,272
MCDL amortization	930	825	908	1,781	2,689
DD&A	4,567	3,239	1,269	6,692	7,961
Total:					
Adjusted DD&A	124,886	159,894	22,352	153,177	175,529
MCDL amortization	134,469	208,468	33,347	148,399	181,746
DD&A	$259,355	$368,362	$55,699	$301,576	$357,275

2005 vs. 2004. Adjusted DD&A for 2005 decreased by $35.0 million (22%) compared to 2004 primarily due to reduced depreciation from Pertra of $32.3 million as Pertra is only included for two months of 2005 compared to a full year for 2004.

MCDL Amortization for 2005 decreased by $74.0 million (35%) as compared with 2004. Amortization for 2005 included $35.4 million of non-sales related amortizations (minimum amortization of $20.4 million and write-downs of $15.0 million), compared to $48.8 million in 2004. Please read note 2 of the consolidated financial statements included in Item 18 of this annual report for a description of our policy related to amortization of multi-client library. In total, MCDL Amortization as a percentage of multi-client revenues was 46% in 2005 compared to 81% in 2004. Excluding the non-sales related amortization, the amortization was 34% and 62% of revenues in 2005 and 2004 respectively, reflecting generally lower amortization rates on sales in 2005 as well as a significant increase in sales relating to surveys that were already fully amortized ($150.6 million in 2005 compared to $65.8 million in 2004).

In 2005 the net book value of our multi-client library was reduced by $25.3 million as a result of the recognition of deferred tax assets, which had been offset by full valuation allowance when we adopted fresh-start reporting on November 1, 2003 (please see "— Critical Accounting Policies and Estimate — Deferred Tax Assets" above). As such, this reduction is not a policy or judgment relating to the multi-client library, but an application of AICPA Statement of Opinion ("SOP") 90-7, "Financial Reporting by Entities in Reorganization under the Bankruptcy Code", which requires realization of pre-restructuring tax assets to be recorded as a reduction of intangible assets recognized upon adoption of fresh-start reporting (see separate section for income tax expense below). Additional realization of such valuation allowance, and corresponding reduction of the net book value of intangible assets, may occur in future periods.

2004 vs. 2003. Adjusted DD&A for 2004 decreased by $15.6 million (9%) compared with 2003 (combined) primarily due to reduced depreciation in Marine Geophysical ($14.0 million) and Production ($7.0 million). Reductions in those two segments were partly offset by increased depreciation and depletion of oil and gas assets in Pertra, reflecting increased production. Depreciation in Marine Geophysical and Production generally decreased due to the significant reduction in carrying values of fixed assets as a result of our adoption of fresh-start reporting effective as of November 1, 2003, partly offset by a reduction of the estimates of the useful depreciable lives for several of the assets in our seismic and FPSO fleet. Additionally, depreciation capitalized as part of the cost of multi-client library was reduced by $9.1 million to $4.0 million in 2004.

MCDL Amortization for 2004 increased by $26.7 million (15%) as compared with 2003 (combined). The increase relates primarily to charges for minimum amortization that amounted to $28.9 million and additional amortization of $19.9 million to write certain surveys down to fair value compared to minimum amortization of $36.6 million in 2003 (impairments were presented separately). Please read note 2 of the consolidated financial statements included in Item 18 of this annual report for a description of our policy related to amortization of multi-client library. In total, MCDL Amortization as a percentage of multi-client revenues was 81% in 2004 compared to 76% in 2003.

Selling, General and Administrative Costs

Selling, general and administrative costs in 2005 increased by $2.6 million as compared with 2004 to $67.4 million. The primary reason for the increase is increased bonus expenses to a broad category of employees due to achievement of key performance indicators under the bonus program established for 2005, partly offset by a reduction due to Pertra only being included for two months in 2005. Also, because we incur most of our selling, general and administrative costs in Norwegian kroner and other currencies other than the U.S. dollar, the weakening of the U.S. dollar against these currencies increased our reported cost.

Selling, general and administrative costs in 2004 increased $13.1 million as compared with 2003 (combined). The increase was caused by various factors. We increased substantially our effort in several areas including internal audit, internal control and compliance; business development and business improvement projects; and human resources. Our selling costs increased because our multi-client late sales increased substantially. We incurred increased bonus expenses to a broad category of employees due to achievement of key performance indicators under the bonus program that we established for 2004. Also, a weakening of the U.S. dollar increased our reported costs.

Impairment of Long-Lived Assets

Since we generally evaluate our multi-client library on a survey-by-survey basis at the end of each year, we expect to write down the value of some surveys each year due to survey specific factors. In 2005 and 2004, we reported no impairments related to the multi-client library since we classified as amortization, rather than impairments, $15.0 million and $19.9 million, respectively, in write downs of individual surveys that related to individual survey-specific factors and that were not individually material. In 2005 we recognized an impairment charge of $4.6 million related to our decision to convert the vessels used in our seafloor 4C operations to towed streamer operations.

In the first ten months (Predecessor) of 2003, we had impairments of $95.0 million, which included $90.0 million of impairment of multi-client library and $5.0 million of impairments related to other assets and equipment.

Gain on Sale of Subsidiaries, Net

In 2005, we recognized $156.4 million of net gains on the sale of subsidiaries. This primarily related to the sale of Pertra with a gain of $157.9 million, partially offset by loss of $1.5 million on the sale of our Norwegian Reservoir Services subsidiary. We had no such gains in 2004 or 2003.

Other Operating (Income) Expense, Net

We recorded other operating income, net, of $26.1 million in 2005. The amount includes a gain of $17.2 million from the release of liabilities related to our UK leases (as described in further detail in the section "— Liquidity and Capital Resources — UK Leases" below) and a gain of $8.9 million from the successful resolution of a claim against an equipment supplier. In 2004 we recorded other operating expense, net, of $8.1 million, primarily relating to costs to complete the 2002 U.S. GAAP consolidated financial statements and the re-audit of our U.S. GAAP financial statements for the year ended December 31, 2001. In 2003 (combined) we recorded other operating expense, net, of $22.4 million, primarily relating to severance payments that aggregated $19.8 million.

Interest Expense and Other Financial Items

Interest expense for 2005 amounted to $96.4 million, a reduction of $14.4 million from 2004. The decrease reflects a significant reduction of interest-bearing debt and capital leases between the two periods. Interest expense for 2004 totaled $110.8 million compared to $99.0 million for the first ten months (Predecessor) and $16.9 million for the last two months (Successor) of 2003. Our average interest bearing debt was significantly lower in 2004 compared to 2003, but in 2003 most of our debt did not accrue interest for approximately 100 days while we were in Chapter 11 proceedings.

Income from associated companies totaled $0.3 million in 2005 compared to $0.7 million in 2004 and $1.0 million in 2003 (combined).

Other financial items, net, amounted to income of $5.9 million in 2005 compared to an expense of $10.9 million in 2004. The improvement of $16.8 million primarily relates to a foreign exchange gain of $4.1 million in 2005 compared to a loss of $8.0 million in 2004. Interest income increased by $2.6 million and we received a consent fee of $3 million in 2005 for certain changes to our UK leases. In 2004, we had other financial expenses of $10.9 million in 2004 compared to an expense of $5.7 million in 2003 (combined).

In 2005, we completed a refinancing of a substantial portion of our long-term debt and credit facilities and in particular the notes we issued in the 2003 financial restructuring. In March 2005, we redeemed $175 million of the $250 million 8% Senior Notes due 2006 at 102% of par value. In November we redeemed the remaining $75 million of the notes at 101% of par value. In December we completed a tender offer and consent solicitation for the $746 million 10% Senior Notes due 2010. As a result, approximately $741.3 million aggregate principal amount of the notes were retired at a price of 113.64% of par value. The total cost of the refinancing, net of the aggregate amount of new debt incurred, was $107.3 million, including repayment premiums and expenses. This amount was charged to expense in 2005 and classified as debt redemption and refinancing cost. We did not incur any comparable costs for 2004 or 2003.

Reorganization Items

In connection with our Chapter 11 reorganization, which we completed in 2003, we recorded reorganization items in our consolidated statement of operations totaling $3.5 million in expenses for 2004 and the following items in 2003:

- for the first ten months (Predecessor) we recorded a gain on debt discharge of $1,253.9 million and costs of reorganization of $52.3 million;
- for the last two months (Successor) we recorded $3.3 million in costs of reorganization; and
- for the first ten months (Predecessor) we recorded the net effect at November 1, 2003, of adopting fresh start reporting of $532.3 million. This amount represents the net effect of differences between the

fair value of our assets and liabilities as measured at November 1, 2003 and the carrying value of those assets and liabilities immediately before adoption of fresh start reporting.

We describe our financial restructuring in more detail under "— 2003 Financial Restructuring" above and in note 3 of the notes to our consolidated financial statements included in Item 18 of this annual report. We describe our adoption of fresh start reporting in more detail under "— 2003 Fresh Start Reporting and Changes in Accounting Policies" above and in note 3 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Income Tax Expense

Income tax expense was $21.8 million in 2005 compared with $48.0 million in 2004 and $18.1 million in 2003 (combined), excluding tax relating to discontinued operations and the adoption of fresh start reporting. Tax expenses in 2005 included current taxes of $10.8 million and net deferred tax expenses of $11.0 million. Taxes payable related primarily to foreign taxes in regions where we are subject to withholding taxes or deemed to have a permanent establishment and where we had no carryover losses. Current taxes included $2.7 million in income related to tax contingencies.

At December 31, 2005, we had a total of $623 million of deferred tax assets (net of deferred tax liabilities) in different jurisdictions, predominantly in Norway and the UK. At adoption of fresh-start reporting on November 1, 2003 and at December 31, 2004, we established valuation allowances for all of our deferred tax assets, with the exception of tax assets relating to Pertra. A valuation allowance, by tax jurisdiction, is established when it is more likely than not that all or some portion of the deferred tax assets will not be realized. The valuation allowance is periodically adjusted based upon the available evidence. During 2005, we concluded that certain valuation allowances are no longer necessary as available evidence, including recent profits and estimates of projected near term future taxable income, supported a more likely than not conclusion that the related deferred tax assets would be realized. As a result, in 2005 we released a portion of the valuation allowance, resulting in the recognition of a deferred tax asset of $20 million in the balance sheet at December 31, 2005. For more information about how we evaluate the need for valuation allowances related to deferred tax assets, including the effects of realizing the benefits of deferred tax assets for which a valuation allowance was established at the adoption of fresh start reporting, please read note 21 of the consolidated financial statements included in Item 18 of this annual report.

Tax expenses in 2004 included current taxes of $20.8 million and net deferred tax expenses of $27.2 million. Current taxes included a $9.5 million charge related to tax contingencies. Deferred tax expense related primarily to Pertra where we made a full deduction of capital expenditures for tax purposes in the year these were incurred. Pertra was subject to petroleum taxation rules in Norway at a nominal tax rate of 78%, where we could not offset its income against losses from other operations.

Tax expenses in 2003 included current taxes of $24.0 million and net deferred tax benefits of $5.9 million.

Discontinued Operations

In 2005, we recognized income from discontinued operations, net of tax, of $0.5 million relating to the sale of our Production Services subsidiary in 2002. In 2004, we recognized income from discontinued operations, net of tax, of $3.0 million relating to the same subsidiary. In 2003, loss from discontinued operations, net of tax, amounted to $2.3 million for the first ten months (Predecessor) and $0.1 million for the last two months (Successor).

Operating Profit (Loss) and Net Income (Loss)

Operating profit for 2005 was $335.4 million, compared to a profit of $35.7 million for 2004. In 2003 we recorded a profit of $9.8 million for the first ten months (Predecessor) of 2003, which included impairment charges of $95.0 million, and a profit of $10.7 million for the last two months (Successor) of 2003.

We reported net income of $112.6 million for 2005, compared to a net loss of $134.7 million for 2004. For 2003 we reported net income of $557.0 million for the first ten months (Predecessor) and a net loss of

$10.0 million for the last two months (Successor). As described above, net income for the first ten months of 2003 is significantly impacted by the effects of our financial reorganization, including a gain on debt discharge of $1,253.9 million, adoption of fresh start reporting ($532.3 million), and impairment charges ($95.0 million).

Segment Operating Profit

Segment operating profit is an integral part of how we monitor the performance of our businesses. A reconciliation of operating profit/(loss) for 2005 and segment operating profit by year are presented in the tables below. The individual reconciling items are discussed in separate paragraphs above. Please read Note 27 to our consolidated financial statements included in Item 18 of this annual report for a reconciliation of segment operating profit to income (loss) before income tax expense (benefit) and minority interest.

2005	Operating Profit/(Loss)	Other Operating (Income)/Expense	Net (Gain) on Sale of Subsidiaries	Impairment of Long-Lived Assets	Segment Operating Profit
	(In thousands of dollars)				
Marine Geophysical	$154,501	$ (8,847)	$ —	$4,575	$150,229
Onshore	(9,803)	—	—	—	(9,803)
Production	43,491	—	—	—	43,491
Pertra	(1,507)	—	—	—	(1,507)
Reservoir/Shared Services/ Corporate	147,841	(17,248)	$(156,382)	—	(25,789)
Elimination	924	—	—	—	924
Total	$335,447	$(26,095)	$(156,382)	$4,575	$157,545

Segment Operating Profit	Successor Company			Predecessor Company	Combined
	Years Ended December 31, 2005	Years Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Twelve Months Ended December 31, 2003
	(In thousands of dollars, except percentage data)				
Marine Geophysical	$150,229	$(34,980)	$ 1,772	$ 41,782	$ 43,554
Onshore	(9,803)	(4,535)	1,778	19,741	21,519
Production	43,491	77,769	11,878	66,876	78,754
Pertra	(1,507)	28,120	(3,198)	17,236	14,038
Reservoir/Shared Services/Corporate	(25,789)	(20,986)	(476)	(19,475)	(19,951)
Elimination	924	(1,593)	—	—	—
Total	$157,545	$ 43,795	$11,754	$126,160	$137,914

Marine Geophysical — Marine Geophysical reported a segment operating profit of $150.2 million in 2005 compared to a loss of $35.0 million in 2004. This improvement was primarily driven by a significant improvement in contract performance and lower multi-client amortization rates (see " — Depreciation, Depletion and Amortization" above).

Marine Geophysical reported a segment operating loss of $35.0 million in 2004 compared to a profit of $43.6 million in 2003. This was driven primarily by weaker performance in the contract market, especially in the first half of 2004 when we experienced weak prices, operating disturbances and higher costs of sales.

Onshore — Onshore recorded a segment operating loss of $9.8 million in 2005 compared to a loss of $4.5 million in 2004. The weak result, despite increased revenues, relates primarily to mobilization and start-up costs for projects at the end of 2005. Onshore is expected to realize strong results in the first half of 2006 because a significant portion of mobilization costs on large projects have been recognized in 2005, while most of the revenue generating activities will be performed in 2006. Compared to the Onshore segment operating profit of $21.5 million in 2003, we saw a decline by $26.0 million in 2004, which was primarily due to a reduction of activity on profitable contracts in South America.

Production — Production recorded a segment operating profit of $43.5 million in 2005, which represents a reduction of $34.3 million from 2004. This reduction was caused by a combination of a reduction of revenues from all vessels except *Petrojarl Varg* and increased costs. For 2003, the segment operating profit was $78.8 million, which was 1% higher than 2004.

Pertra — Pertra recorded a segment operating loss of $1.5 million for two months of operations in 2005, compared to full year profit of $28.1 million for 2004 and $14.0 million for 2003.

For more information regarding segment operating profit, please see Note 27 to our consolidated financial statements included in Item 18 of this annual report.

Outlook; Factors Affecting Our Future Operating Results

Our future operating results will depend on numerous factors, including those described under "Key Information — Risk Factors" in Item 3 of this annual report. Factors that will impact our future operating results include, but are not limited to, the following:

- our ability to complete a separation of our geophysical and productions businesses;
- the development of our main market drivers, which includes prices and price expectations for oil and natural gas. Such prices and price expectations affect the demand for exploration and production related seismic services and the economics in developing and producing small and medium sized oil and natural gas fields;
- our ability to optimize performance of our FPSO vessels and profitably expand the Production segment, including, among others:
  - sustaining high regularity and uptime;
  - maximizing volumes and revenues under current contracts, including further extension of contract duration where appropriate; and
  - capturing new profitable contract opportunities and achieving timely redeployment of vessels on terms and at volumes reflecting their production capacities;
- the business performance of our Onshore and Marine Geophysical segments, including, among others:
  - the demand for contract seismic services, coupled with (a) our ability to benefit from our strong HD3D℠ position and high productivity and vessel performance, (b) our ability to reduce steaming and other unproductive vessel time, and (c) the prices for our services;
  - demand for multi-client seismic data in various geographic regions, including future licensing rounds and demand for data offshore Brazil;
  - our ability to profitably rebuild new multi-client seismic survey activity to complement our contract work; and
  - implementation of our streamer expansion and replacement program for our seismic vessels;
- foreign currency exchange rate fluctuations between the U.S. dollar, our functional currency, and the Norwegian kroner or the British pound, which will generally have an impact on our operating profit because we have significant operating expenses in Norwegian kroner and British pounds;
- the extent to which we participate in strategic acquisitions or dispositions of assets or businesses or in one or more joint ventures involving such assets or businesses; and
- our ability to continue to develop or acquire competitive technological solutions for our different business units.

The markets in which we operate showed strong improvement in 2005. Oil prices remained at high levels, and oil companies increased their exploration and production (E&P) spending. E&P spending is expected to increase further in 2006 and, in the medium to long term, high oil price levels are expected to positively impact our core markets.

The global marine seismic fleet was at full capacity utilization in 2005. We believe that demand will increase further in 2006, outweighing increase of marine seismic capacity and resulting in further improved prices. Within floating production, increased focus on smaller fields and tail-end optimization forms a basis for growth in outsourcing where our floating production activity is well positioned with market leadership in the North Sea and the potential to grow in selected international markets.

In 2006, we expect the following factors to influence our performance:

Marine Geophysical

- Marine 3D industry seismic fleet at full capacity utilization with our streamer contract operating profit margins expected to improve by more than 10 percentage points compared to full year 2005, assuming that we do not experience any unexpected significant increase in operating costs or any significant operating disturbances relating to our contract operations;
- Multi-client late sales expected to be lower than 2005 as a result of low levels of investments in recent years; and
- Cash investments in multi-client library expected to double from an investment of $46 million in 2005, with continued high pre-funding levels.

Onshore

- Revenues and operating profit expected to be significantly above 2005 levels; and
- Cash investments in multi-client library expected to more than double from an investment of $8 million in 2005.

Production

- Revenues expected to be slightly lower than full year 2005; and
- Operating expenses, including maintenance, expected to be in line with 2005.

For a discussion regarding our expected capital expenditures in 2006, please see "Liquidity and Capital Resources — Capital Requirements and Commitments" below.

Liquidity and Capital Resources

Liquidity — General

We believe that our cash balances and our available borrowing capacity under the credit agreement established in December 2005 will be adequate to meet our working capital and liquidity needs for the remainder of 2006 and 2007. While we believe that we have adequate sources of funds to meet our liquidity needs for the 2006-2007 period, our ability to meet our obligations in the longer term depends on our future performance, which, in turn, is subject to many factors beyond our control. See "Key Information — Risk Factors" in Item 3 of this annual report.

Sources of Liquidity — Capital Resources

Our internal sources of liquidity are cash and cash equivalents and cash flow from operations. Cash and cash equivalents totaled $121.5 million at December 31, 2005, compared to $132.9 million at December 31, 2004.

Net cash provided by operating activities totaled $279.1 million in 2005, compared to $282.4 million in 2004. In 2005, accounts receivable increased by $52.3 million, after an increase in revenues by $66.8 million in 2005 compared to 2004, while accounts payable decreased by $7.6 million. Generally, our subsidiaries are not subject to restrictions on their ability to transfer funds to us that would materially affect our ability to meet our cash obligations.

In December 2005, we entered into a new credit agreement, establishing a term loan of $850 million ("Term Loan") and a revolving credit facility ("RCF") of $150 million. The Term Loan amortizes 1% per annum with the remaining balance due in 2012, and bears interest at a rate of the London Interbank Offered Rate ("LIBOR") plus a margin that depends on our leverage ratio. For purposes of the credit agreement, leverage ratio is the ratio of consolidated indebtedness to consolidated EBITDA, as defined in the credit agreement, reduced by multi-client investments made for the period in question. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.5% per annum. Below that level, the margin will be 2.25% per annum. We are required to make principal repayments at a minimum level of 0.25% of the initial principal amount of the Term Loan per quarter. The credit agreement contains provisions that generally require us to apply 50% of excess cash flow to repay outstanding borrowings for periods when our leverage ratio exceeds 2:1. We can make optional payments to reduce the principal at no penalty. Excess cash flow for any period is defined as net cash flow provided by operating activities during that period less capital expenditures made in that period or committed to be made in the next period, less debt service payments and less accrued income taxes to be paid in the next period. The Term Loan is an obligation of PGS ASA and PGS Finance Inc. as co-borrower, and is secured by pledges of shares of certain material subsidiaries and guaranteed by certain material subsidiaries.

The credit agreement also establishes the RCF. We may borrow U.S. dollars, or any other currency freely available in the London banking market to which the lenders have given prior consent, under the RCF for working capital and for general corporate purposes. Up to $60 million of the RCF can be used for letters of credit. Letters of credit, which can be obtained in various currencies, can be used to secure, among other things, performance and bid bonds required in our ongoing business. The RCF is secured by pledges of shares of material subsidiaries. The RCF matures in 2010. Borrowings under the RCF bear interest at a rate of LIBOR plus a margin that depends on our leverage ratio. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.25%; at a ratio between 2:1 and 2.25:1, the applicable margin will be 2.00%; and at a ratio below 2:1, the applicable margin will be 1.75. At December 31, 2005, $14.6 million of letters of credit were issued under the RCF.

In February 2005 we established an overdraft facility on NOK 50 million as part of our Norwegian cash pooling arrangement.

Our external sources of liquidity include the $150 million revolving credit facility established in December 2005 as part of our $1 billion senior secured revolving credit facility described above. As of December 31, 2005, we had unused borrowing capacity of $135.4 million under the revolving credit facility. Ongoing trade credit will also be a source of liquidity. Subject to market conditions and other factors, we might also seek to raise additional debt or equity in the capital markets.

The book value of our debt, including capital leases, was approximately $980 million as of December 31, 2005 compared to approximately $1,164 million at December 31, 2004.

Our debt consisted of the following primary components at December 31, 2005:

	(In millions of dollars)
10% Senior Notes, due 2010	$ 5
8.28% First Preferred Mortgage Notes, due 2011	88
Term loan due 2012	850
Other loans due 2006	3
Total debt	$946
Capital leases	34
Total	$980

Net interest bearing debt (interest bearing debt, including capital leases, less cash and cash equivalents, restricted cash and interest bearing investments) was approximately $829 million as of December 31, 2005 compared to $995 million as of December 31, 2004.

Our December 2005 credit facility contains financial covenants and negative covenants that restrict us in various ways. The facility provides that

- our total leverage ratio may not exceed 3.50 to 1.0 in 2006, 3.25 to 1.0 in 2007 and 3.00 to 1.0 in 2008 and may not exceed 3.00 to 1.0 at the time of our proposed separation transaction described under "Information on the Company — Proposed Separation of the Geophysical and Production Businesses" in Item 4 of this annual report
- our consolidated interest coverage ratio (defined as the ratio of consolidated EBITDA, as defined in the credit agreement, reduced by multi-client investments to consolidated interest expense) must be at least 3.0 to 1.0, and
- our consolidated fixed charge coverage ratio (defined as the ratio of consolidated EBITDA, as defined in the credit agreement, reduced by multi-client investments to consolidated fixed charges) must be at least 1.3 to 1.0.

In addition, the credit agreement restricts our ability, among other things, to sell assets; incur additional indebtedness or issue preferred stock; prepay interest and principal on our other indebtedness; pay dividends and distributions or repurchase our capital stock; create liens on assets; make investments, loans, guarantees or advances; make acquisitions; engage in mergers or consolidations; enter into sale and leaseback transactions; engage in transactions with affiliates; amend material agreements governing our indebtedness; change our business; enter into agreements that restrict dividends from subsidiaries; and enter into speculative financial derivative agreements.

We experience some seasonality in our business, and our capital requirements may be impacted by this seasonality. For more information relating to the seasonality of our business, see "— Seasonality" above.

For further information relating to our indebtedness as of December 31, 2005 and the maturities of such indebtedness, please read note 16 of the notes to our consolidated financial statements in Item 18 of this annual report.

Net Cash Used in or Provided by Investing and Financing Activities

Net cash provided by investing activities totaled $10.5 million in 2005, compared to net cash used of $183.4 million in 2004. The change of $193.9 million was primarily due to (a) $155.4 million in net proceeds from the sale of Pertra and additional consideration relating to the sale of Production Services in 2002, (b) a decrease in capital expenditures of $57.9 million, offset in part by (c) a $14.6 million increase in investment in multi-client library.

The large decrease in capital expenditures reflects the divestment of Pertra, which had capital expenditures of $85.0 million in 2004 compared to $0.1 million reflected in the first two months of 2005 in which it was a part of our company. The other business areas had an increase in capital expenditures of $27.0 million, mainly divided into Marine Geophysical ($15.3 million) and Onshore ($11.2 million). The increases are mainly due to increased capital expenditures on our streamer replacement and expansion program in Marine Geophysical and more normal spending on seismic equipment in Onshore after a very low level in 2004.

Net cash used in financing activities totaled $301.0 million in 2005., compared to $71.3 million in 2004. In 2005, we made net repayments of long-term debt and principal payments under capital leases totaling $184.9 million, compared to net repayments in 2004 of $47.1 million. In 2004 we made a $22.7 million distribution of excess cash to creditors in connection with our 2003 financial restructuring, with no similar distribution during 2005.

In 2005 we repaid all of our $250 million 8% Senior Notes at a redemption premium totaling $4.3 million. We also repaid $741.3 million of the $745.9 million 10% Senior Notes at a tender and consent premium of

$101.2 million. Costs associated with refinancing the long-term debt were approximately $9.9 million, capitalized as deferred debt issue costs.

Capital Requirements and Commitments

Our capital requirements are affected primarily by our results of operations, capital expenditures, investment in multi-client library, debt service requirements, lease obligations, working capital needs and outcome of significant contingencies. The majority of our ongoing capital requirements, other than debt service, lease obligations and contingencies, consist of:

- capital expenditures on seismic vessels and equipment, including data processing equipment and streamers;
- investments in our multi-client library; and
- working capital related to growth, seasonality and specific project requirements.

Since we sold our oil and natural gas subsidiary Pertra in March 2005, we do not have any ongoing capital requirements related to these operations. We had substantial capital expenditures in Pertra in 2004.

In prior years, our capital expenditures have related not only to normal ongoing equipment replacement and refurbishment needs, but also to increases in our seismic data acquisition capacity and in our FPSO operations. Such expenditures, which can be substantial from time to time, depend to a large extent upon the nature and extent of future commitments that are largely discretionary. In 2005 we accelerated the replacement of streamers and at the same time expanded streamer capacity in Marine Geophysical. In Onshore we increased the spending on seismic equipment from a low level in 2004.

The following table sets forth our consolidated capital expenditures in 2005, 2004 and 2003:

Business Segments	2005	2004	2003
	(In million of dollars)		
Marine Geophysical	$72.2	$ 56.9	$16.1
Onshore	12.6	1.4	7.0
Production	—	1.0	0.5
Other	5.6	4.1	0.3
Pertra	0.1	85.0	34.2
Total	90.5	148.4	58.1
Investments in multi-client library	$55.7	$ 41.1	$90.6

For 2006, we expect:

- to approximately double our cash investment in our Marine Geophysical multi-client library from an investment of $46 million in 2005, with continued high pre-funding levels, and approximately double the cash investment in our Onshore multi-client library from an investment of $8 million in 2005;
- capital expenditures, in addition to the investment in the new Ramform seismic vessel newbuild described below, of $90-100 million in Marine Geophysical, primarily related to our streamer expansion and replacement program, and of approximately $10 million in Onshore; and
- capital expenditures in Production on our existing vessels to continue at a low level because our FPSO vessels are not expected to have substantial replacement needs through 2006.

In 2006, we acquired the tanker *Rita Knutsen* to have available for later conversion to an FPSO. The acquisition cost for the tanker of $35 million was paid in January and March 2006. The capital expenditures for a conversion into an FPSO will be substantial and will depend on the particular project.

Under our current streamer expansion, upgrade and replacement program, we expect to spend approximately $50 million on marine seismic streamers in 2006 and approximately $30 million to $35 million per year in the period 2007 to 2010. Since this program is discretionary, however, we may in the future change the scope and annual capital expenditure related to the program. We also intend to make maintenance and refurbishment expenditures as required so as to maintain our fleet of marine seismic and FPSO vessels in good working order. We intend to make other capital expenditures in our business segments as conditions dictate and financial resources permit. Finally, we may also incur capital expenditure significantly above the amounts described above to pursue new business opportunities for any of our business segments.

In March 2006, we announced that we intend to build a new third generation Ramform seismic vessel at Aker Yards, Langsten, Norway. We currently expect delivery in the first quarter 2008. We expect the new vessel to cost approximately $85 million, excluding the cost of seismic equipment, and we expect the total cost to be approximately $160 million, excluding project management cost and interest. Payments to the yard will be made in five equal installments, with two due in 2006, two due 2007, and the final payment due upon delivery of the vessel, which is expected in 2008. Payments for seismic equipment will be made over this payment period. The total payments relating to the newbuild project in 2006 are estimated to be approximately $55 million.

Off-Balance Sheet Arrangements

For a discussion of our UK leases, see " — UK Leases" below.

Long-Term Contractual Obligations

The following table presents our long-term contractual obligations related to our loan and lease agreements and other long-term liabilities and related payments due in total and by period as of December 31, 2005:

		Payments Due by Period			
Contractual Obligations	**Total**	**2006**	**2007-2008**	**2009-2010**	**Thereafter**
	(In million of dollars)				
Long-term debt obligations	$ 943.9	$21.7	$ 43.9	$ 53.2	$825.1
Operating lease obligations(b)	158.5	39.2	54.2	37.2	27.9
Capital lease obligations	33.7	20.5	13.2	—	—
Other long-term liabilities(a)	103.5	15.7	29.6	22.8	35.4
Total	$1,239.6	$97.1	$140.9	$113.2	$888.4

(a) Excluding other long-term liabilities that are contingent and not determinable with respect to the timing of future payments (see the table below captioned "Other Long-Term Liabilities").

(b) Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above is charter hire for the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. We are required to charter the vessel for as long as the *Ramform Banff* produces the Banff field, which could extend to 2014 depending on the customer/field operator. The maximum payment for the charter through 2014 is $97.8 million.

For additional information about the components of our long-term debt and lease obligations, please refer to notes 16 and 20 to the consolidated financial statements included in Item 18 of this annual report.

The table below is provided to illustrate the expected timing of future payments related to other long term-liabilities reported in our consolidated balance sheet as of December 31, 2005. Determining the expected future cash flow presented in the table requires us to make estimates and assumptions since the timing of any payments related to these long-term liabilities generally is not fixed and determinable but rather depends on future events. We believe that our estimates and assumptions are reasonable, but actual results may vary from what we have estimated or assumed. As a result, our reported liabilities and expenses could be materially affected if the assumptions and estimates we have made were changed significantly.

Other Long-Term Liabilities	Total	Payments Due by Period 2006	2007-2008	2009-2010	Thereafter	Not Determinable
		(In millions of dollars)				
Other long-term liabilities:						
Pension liability(a)	$ 45.4	$ 7.0	$14.0	$ 8.7	$15.7	$ —
Asset removal obligation(b)	20.0	0.3	—	—	19.7	—
Accrued liabilities related to our UK leases:						
— related to interest rate differential(c)	38.1	8.4	15.6	14.1	—	—
— related to tax indemnifications	12.7	—	—	—	—	12.7
Tax contingencies	19.2	—	—	—	—	19.2
Other	5.4	—	—	—	—	5.4
Total	$140.8	$15.7	$29.6	$22.8	$35.4	$37.3

(a) We have projected benefit plans in Norway and in UK. Pension liability represents the aggregate shortfall of pension plan assets compared to projected benefit obligations for our plans, as recognized in our consolidated balance sheet. We will pay this obligation over time, as adjusted for changes in estimates relating to obligations and assets, in accordance with the funding requirements of the life insurance companies through which we fund our plans in Norway and in accordance with the funding practice that we agree with the trustees of our pension scheme in UK. Such requirements are subject to change over time, but we expect these payments to be made over several years.

(b) Asset removal obligation as of December 31, 2005 primarily relates to the *Ramform Banff* operations.

(c) The estimated net present value of future payments related to interest rate differential on our UK leases as of December 31, 2005 is $54.5 million based on forward interest rate curves, which is $16.4 million higher than the amount included in accrued liabilities from fresh-start reporting. Payments through the year 2008 reflect estimated total payments based on forward interest rate curves as of December 31, 2005. The amount presented for 2009-2010 is the residual amount.

UK Leases

We entered into capital leases from 1996 to 1998 relating to *Ramform Challenger, Valiant, Viking, Victory* and *Vanguard*; the FPSO *Petrojarl Foinaven*; and the production equipment for the *Ramform Banff*. The terms for the leases range from 13-25 years. We have indemnified the lessors for the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities and for variations in actual interest rates from those assumed in the leases. There are no limits on either of these indemnities.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Although the UK Inland Revenue generally deferred for a period of time agreeing to the capital allowances claimed under such leases pending the outcome of a legal proceeding in which the Inland Revenue was challenging capital allowances associated with a defeased lease, in November 2004, the highest UK court of appeal ruled in favor of the taxpayer and rejected the position of the Inland Revenue. In connection with the adoption of fresh start reporting on November 1, 2003 and before the November 2004 ruling, we recorded a liability of 16.7 million British pounds (approximately $28.3 million). We release applicable portions of this liability if and when the Inland Revenue accepts the lessors' claims for capital allowances under each lease. In 2005 we released 9.4 million British pounds (approximately $17.2 million) of the liability.

The remaining accrued liability at December 31, 2005 of 7.3 million British pounds (approximately $12.7 million) relates to the *Petrojarl Foinaven* lease where the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available. If the Inland Revenue were successful in challenging that rate, the lessor would be liable for increased taxes on *Petrojarl Foinaven* in early periods (and decreased taxes in later years), and our rentals would increase. How much the rentals could increase depends primarily on how much of the asset will be subject to a different depreciation rate. Management believes that 60 million to 70 million British pounds (approximately $104 million to $121 million) represents a worst case scenario for this liability.

The leases are legally defeased because we have made payments to independent third-party banks in consideration for which these banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, we receive rental rebates. Conversely, if actual interest rates are less than the assumed interest rates, we pay rentals in excess of the defeased rental payments. Over the last several years, the actual interest rates have been below the assumed interest rates. Prior to November 1, 2003, we had deferred a portion of a deferred gain representing the net present value of additional required rental payments as of the inception of each lease. Such deferred gain was amortized over the terms of the leases. Effective November 1, 2003, we adopted fresh start reporting, and recorded a liability equal to the fair value of the future additional required rental payments based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, 24.6 million British pounds (approximately $47.2 million) at December 31, 2004 and 22.0 million British pounds (approximately $38.1 million) at December 31, 2005.

Currently, interest rates are below the assumed interest rates. Based on forward market rates for Sterling LIBOR, the net present value, using an 8% discount rate, of the additional required rental payments aggregated 31.5 million British pounds (approximately $54.5 million) as of December 31, 2005. Of this amount, 1.2 million British pounds (approximately $2.0 million) was accrued at December 31, 2005, in addition to the remaining fresh start liability as described above.

Additional required rental payments were $7.2 million for each of the years ended December 31, 2005 and 2004, $4.9 million for the two months ended December 31, 2003 (Successor) and $1.5 million for the ten months ended October 31, 2003 (Predecessor).

For additional information regarding our UK leases, please see notes 2 and 20 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Research and Development

We incurred research and development costs of $9.9 million, $3.4 million and $2.6 million during the years ended December 31, 2005, 2004 and 2003, respectively. For additional information regarding our research and development policies and expenditures, please see "Information on the Company — Other Factors Related to Our Business — Our Research and Product Development" in Item 4 and our consolidated statements of operations in Item 18 of this annual report.

ITEM 6. *Directors, Senior Management and Employees*

Board of Directors

The table below provides information about our directors as of March 31, 2006:

Name (Age)	Position	Director Since	Term Expires(a)	Share Ownership
Jens Ulltveit-Moe(63)	Chairman	2002	2006	3,087,332
Keith Henry(61)	Vice Chairman	2003	2006	—
Francis Gugen(57)	Director	2003	2006	—
Harald Norvik(59)	Director	2003	2006	—
Rolf Erik Rolfsen(65)	Director	2002	2006	—
Clare Spottiswoode(53)	Director	2003	2006	—
Anthony Tripodo(53)	Director	2003	2006	—

(a) The annual general meeting is scheduled to occur on June 14, 2006

Mr. Ulltveit-Moe has been our chairman of the Board of Directors since September 2002. He is the founder and has been president and chief executive officer of Umoe AS, a shipping and industry company, since 1984. From 2000 to 2004, he was the president of the Confederation of Norwegian Business and Industry. From 1980 to 1984, Mr. Ulltveit-Moe served as managing director of Knutsen OAS. From 1972 to 1980, he was managing director of the tanker division of SHV Corporation. From 1968 to 1972, Mr. Ulltveit-Moe was an associate with McKinsey & Company, Inc. in New York and London. Mr. Ulltveit-Moe holds a master's degree in business administration from the Norwegian School of Economics and Business Administration and a master's degree in international affairs from the School of International Affairs, Columbia University, New York.

Mr. Henry has been our vice chairman of the Board of Directors since October 2003. He served as group executive vice president for the Kvaerner Engineering and Construction Group from March 2000 until June 2003. He was chief executive of National Power Plc from 1995 to 1999 and was chief executive of Brown & Root Limited from 1990 to 1995. He is the senior independent non-executive director at Burren Energy plc and at Emerald Energy Plc, and is a non-executive director of South East Water Limited. He acts as an adviser to a number of construction and energy related organizations. He holds BSc and MSc degrees, and is a Fellow of the Royal Academy of Engineering.

Mr. Gugen is currently active as a consultant and an investor in the energy industry. He served with Amerada Hess Corporation for eighteen years, from 1982 to 2000, holding various positions including chief executive of Amerada Hess UK from 1995 to 2000 and chief executive of northwestern Europe from 1998 to 2000. Mr. Gugen acts as chairman and non-executive director for various other companies, including CH4 Energy Limited, Island Gas Limited and The Britannia Building Society, where he also sits on the audit committee. Mr. Gugen has earlier worked for Arthur Andersen and is a UK chartered accountant.

Mr. Norvik is chairman and a partner of Econ Management, chairman of the Board of Directors for Oslo Stock Exchange, member of the Board of Directors in ConocoPhillips and chairman of the Supervisory Board in DnB NOR ASA. He served as chief executive officer of Statoil ASA from 1988 to 1999. He was finance director and a member of the executive board of the Aker Group from 1981 to 1988. He served as personal secretary to the Prime Minister of Norway and as Deputy Minister in The Ministry of Petroleum and Energy from 1979 to 1981. Mr. Norvik has a Master of Science Degree in Business from The Norwegian School of Economics and Business Administration.

Mr. Rolfsen holds several board positions. He is a member of the board of directors of Technip S.A., Paris and Gaz de France Norge A.S.. He is also chairman of the executive council of the Industrial Development Fund at NTNU in Trondheim. From 1987 to 2000, he was managing director of TOTAL Norge A.S. and from 1999 to 2000 he was also managing director of Fina Exploration Norway. From 1980 to 1986, he was executive vice president of Kongsberg Vapenfabrikk A.S.. He was educated at the College of Commerce in Oslo.

Ms. Spottiswoode has been deputy chairman and senior non-executive director at British Energy since June 2002, acts as chair of British Energy's remuneration committee and has served as an independent director of that company since 2001. She currently acts as non-executive chair of the board of Economatters Ltd. and is a non-executive director of BioFuels, Bergesen Worldwide Gas ASA and Tullow Oil plc.. She is also a member of the board of the Department of Health Commercial Advisory Board and a Policy Holder Advocate for Aviva. She previously held several non-executive director positions including Booker plc.. She was director general of Ofgas, the UK Gas Regulation Organization, from 1993 to 1998. In 1993 she served as a member of the UK Deregulation Task Force, and from 1998 to 2002 sat on the UK Public Services Productivity Panel. Her career started as an economist with the HM Treasury before establishing her own software company. In 1999 she was made a Commander of the Order of the British Empire for services to industry, and holds degrees in economics from Cambridge and Yale University.

Mr. Tripodo has been managing director of Arch Creek Advisors LLC, an investment-banking firm, since 2003. He also serves as a non-executive director for Helix Energy Solutions Group, Inc. (formerly Cal Dive International) and Vetco International Limited, both oilfield service companies, based in Houston, Texas and London, England, respectively. From 1997 to April 2003, Mr. Tripodo served at Veritas DGC in various capacities, including executive vice president and chief financial officer. He also has held various senior executive and financial roles at Baker Hughes and PricewaterhouseCoopers. Mr. Tripodo has a B.A. degree from St. Thomas University.

Committees

Under Norwegian law, decision-making authority may not be delegated by the Board of Directors to its committees or subcommittees. The Board may, however, establish committees to assist it in discharging its responsibilities. Our Board of Directors has appointed two such committees, the audit committee and the remuneration committee.

Our audit committee currently consists of three members, Messrs. Gugen (chairman), Norvik and Tripodo. The Board of Directors has determined that the members of the audit committee are independent under applicable provisions of the Securities Exchange Act of 1934 and New York Stock Exchange listing standards. Our audit committee has adopted a written charter, a copy of which we have filed as an exhibit to this annual report.

The audit committee acts to support the Board of Directors in the administration and exercise of the Board's responsibility for supervisory oversight under applicable Norwegian and other laws and stock exchange listing standards in connection with our financial statements and various audit, accounting and regulatory requirements. The audit committee is responsible for proposing to the full Board, for presentation and election at our annual general meeting of shareholders, the independent registered public accounting firm of our company. The audit committee is also responsible for supporting the Board in the administration and exercise of the Board's responsibility for supervisory oversight in relation to, among other items:

- financial statement and disclosure matters, including our quarterly and annual financial statements and related disclosures;
- reviewing the quarterly and annual financial statements, including reviewing major issues regarding accounting principles and financial statement presentations, the adequacy of our internal controls and discussing significant financial reporting issues and judgments made in connection with preparation of the financial statements;
- provision by the auditor of audit services and permitted non-audit services;
- audits of our financial statements, including reviewing our critical accounting policies and practices;
- our relationship with our independent registered public accounting firm, including the qualifications, performance and independence of the auditors;

• our internal audit function; and

• responsibilities to comply with various legal and regulatory requirements that could affect our financial statements.

The U.S. Securities Exchange Act of 1934 and the listing standards of the New York Stock Exchange require the audit committee of a listed company in the United States, such as PGS, to be directly responsible for the appointment, compensation, retention and oversight of the work of that company's independent registered public accounting firm. Because under Norwegian law the power to appoint, retain and compensate the auditors is held by the shareholders, our audit committee is directly responsible only for the oversight of the work of the auditors and the audit committee and the full Board recommend the appointment, retention and compensation of the auditors to its shareholders for approval. In addition, as a foreign private issuer in the United States, we are not required to publish the audit committee report required by applicable regulations of the SEC for U.S. domestic issuers.

Our remuneration committee consists of Messrs. Henry (chairman) and Rolfsen. The Board of Directors has determined that the members of the remuneration committee are independent under applicable New York Stock Exchange listing standards. The remuneration committee supports the Board of Directors in the administration and exercise of the Board's responsibility for supervisory oversight of overall policy and structure with respect to compensation and incentive matters, including compensation and incentive arrangements for our chief executive officer and other senior executive officers. Our remuneration committee has adopted a written charter, a copy of which we have filed as an exhibit to this annual report. As a foreign private issuer in the United States, we are not required to publish the compensation committee report required by applicable regulations of the SEC for U.S. domestic issuers.

Nomination Committee

The members of the nomination committee are elected by our shareholders in accordance with Norwegian corporate governance best practices. The members of the committee, consisting of Roger O'Neil, Hanne Harlem and C. Maury Devine, are not members of our board of directors. The nomination committee is responsible for making recommendations for consideration by the shareholders relating to:

• individuals who are nominated to serve as members of the Board of Directors and as the chairperson of the Board of Directors;

• individuals who are nominated to serve as members of the nomination committee and as the chairperson of the nomination committee;

• the remuneration of the directors and the members of the nomination committee; and

• any amendments of the nomination committee mandate and charter.

Mr. O'Neil is the chairperson of our nomination committee. He is a former executive of Mobil and executive vice president and member of the executive board of Statoil. Mr. O'Neil has worked as Senior Oil and Gas Advisor in the Corporate Finance Group of Dresdner Kleinworth and Wasserstein and as a consultant for The World Bank. He is a member of the board in Clearvision International, Pearl Energy and Upstream. Mr. O'Neil holds a BS in Chemical Engineering from the University of Notre Dame and an MBA from Cornell University.

Mrs. Harlem has been University Director at the University of Oslo since 2004 and was Minister of Justice in Norway from 2000 to 2001. She is presently chairperson of the board in UniRand, and a member of the board in Gaz de France, Helse Sør and Forskningsparken. Mrs. Harlem has a law degree from the University of Oslo.

Ms. Devine is a former ExxonMobil executive and former Fellow at Harvard University's Kennedy School of Government Belfer Center for Science and International Affairs. She currently is member of the Board of Directors of Independence Air, Det Norske Veritas (DNV) and FMC Technologies. Ms. Devine holds graduate degrees from Middlebury College and Harvard University.

The listing standards of the New York Stock Exchange require U.S. listed companies to have a corporate governance committee (1) to develop and recommend to the board a set of corporate governance guidelines applicable to the listed company and (2) to oversee the evaluation of the board and management. In accordance with Norwegian law and customary practice, our Board of Directors, which is composed entirely of non-management directors, fulfills those responsibilities.

Corporate Governance

We are committed to maintaining high standards of corporate governance and believe that effective corporate governance establishes the framework by which we conduct ourselves in delivering services to our customers and value to our shareholders. Although we are registered in Norway as a public limited company and our governance model is built on Norwegian corporate law, we are subject to the requirements applicable to foreign private issuers in the United States, including those established by the SEC and the NYSE.

Our corporate governance principles are adopted and reviewed periodically by the Board of Directors. The Corporate Governance Principles, together with our Core Values and our Code of Conduct, Audit Committee Charter, Remuneration Committee Charter and our Rules of Procedure for the Board of Directors, are available under the "About PGS" section of our internet website at *www.pgs.com* and in print to any shareholder who requests a copy. Requests should be directed to our investor relations department at ir@pgs.com.

Director Independence

At its meeting held March 22, 2006, our Board of Directors affirmatively determined that each of Francis Gugen, Keith Henry, Harald Norvik, Rolf Erik Rolfsen, Clare Spottiswoode and Anthony Tripodo has no material relationship with us (either directly or as a partner, shareholder or officer of an organization that has a relationship with us) and that each is therefore an "independent" director under applicable NYSE listing standards. These determinations were made by our Board of Directors based on representations made by each of those directors to us, a review of applicable NYSE rules and listing standards and a review of our Rules of Procedures for the Board of Directors.

Shareholders and other interested parties may communicate directly with our independent directors by sending a written communication in an envelope addressed to "Board of Directors (Independent Members)" in care of our General Counsel at the address indicated on the cover of this annual report.

Meetings of Non-management Directors

Our Board of Directors consists of only non-management directors. As such, every meeting of our Board of Directors is a meeting of non-management directors. In addition, if the group of non-management directors includes a director who is not independent under NYSE listing standards, the independent directors will meet in executive session at least once annually. Currently, the director who presides at meetings of the non-management directors is the Chairman of the Board. Further, the director currently presiding at meetings of the independent directors is the Vice-Chairman of the Board.

Certifications

We have filed the required certifications of our chief executive officer and our chief financial officer under Section 302 of the Sarbanes-Oxley Act of 2002 as exhibits 12.1 and 12.2 to this annual report, and we expect to file with the NYSE the chief executive officer certification without exceptions within 30 days following our annual general meeting, as required by Section 303A.12(a) of the NYSE Listed Company Manual.

Executive Officers

The table below provides information about our executive officers as of March 31, 2006:

Name (Age)	Position	Executive Officer Since	Share Ownership
Svein Rennemo (58)	President and Chief Executive Officer	2002	11,544
Gottfred Langseth (39)	Senior Vice President and Chief Financial Officer	2004	1,158
Rune Eng (44)	President — Marine Geophysical	2004	4,308
Eric Wersich (42)	President — Onshore	2003	1,385
Espen Klitzing (42)	President — Production	2005	1,064

Mr. Rennemo joined PGS in November 2002 as president and chief executive officer. Prior to joining PGS, he was a partner in ECON Management. From 1997 to March 2001, Mr. Rennemo was chief executive officer of Borealis, one of the world's largest producers of polyolefin plastics, headquartered in Copenhagen, Denmark, having previously served as chief financial officer and deputy chief executive officer since 1994. From 1982 to 1994, he filled various senior management positions within Statoil, among them group chief financial officer and president of Statoil Petrochemicals. From 1972 to 198.2, he served as a policy analyst and advisor with the Central Bank and the Ministry of Finance in the kingdom of Norway and the OECD Secretariat in Paris. Mr. Rennemo earned a master's degree in economics at the University of Oslo in 1971. He is a non-executive chairman of the Board of Statnett SF (Norway).

Mr. Langseth joined PGS in November 2003 and was named senior vice president and chief financial officer as of January 1, 2004. He was chief financial officer at the information technology company Ementor ASA from 2000 to 2003. Mr. Langseth was senior vice president of finance and control at the offshore construction company Aker Maritime ASA from 1997 to 2000. He served with Arthur Andersen Norway from 1991 to 1997, qualifying as a Norwegian state authorized public accountant in 1993. Mr. Langseth has a master's degree in business administration from the Norwegian School of Economics and Business Administration.

Mr. Eng was appointed president of Marine Geophysical in August 2004. Since joining PGS in 1997, he has held the position of area manager Scandinavia and from 2000 has served as president for the EAME region (Europe, Africa and Middle East). Prior to joining PGS, Mr. Eng held different positions in Fugro-Geoteam, including a board position in Sevoteam, a Russian-Norwegian joint operating company. Mr. Eng has a bachelor's degree in applied geophysics from the University of Oslo and a master of science degree from Chalmers University of Technology (Sweden).

Mr. Wersich joined Onshore in January 2000 as vice president of western hemisphere and was appointed president of Onshore in June 2003. Mr. Wersich worked with Western Geophysical from 1984 to 2000, employed in various operational and management positions in North America, Latin America, Europe and the Middle East. He is a graduate of the Colorado School of Mines, where he earned a bachelor of engineering degree in geophysics.

Mr. Klitzing joined PGS in May 2005 as senior vice president of business development and support. From November 2005, Mr. Klitzing has served as president for PGS Production. From January to April 2005, Mr. Klitzing was a special advisor to the private investment company Kistefos. From 1999 to 2004, he was CEO of Storebrand Livsforsikring (Life Insurance), a company with a premium income of NOK 9.7 billion and 675 employees. Prior to joining Storebrand, Mr. Klitzing held positions with the consulting firm McKinsey & Company Inc. Mr. Klitzing also has served on numerous boards of directors. Mr. Klitzing has a degree in business administration from the Norwegian School of Economics and Business Administration.

Share Ownership of Directors and Executive Officers

As of December 31, 2005, the total number of our shares and ADSs beneficially held by directors (seven persons) and executive officers (five persons) as a group was 3,052,857 representing approximately 5.1% of our outstanding shares. Mr. Ulltveit-Moe, chairman of our Board of Directors, is the founder, chief executive officer and president of Umoe Group, the parent company of Umoe Industri AS, which as of December 31, 2005 owned 3,037,332 shares, or 5.1% of our outstanding shares.

On consummation of our reorganization plan, all outstanding options for shares were cancelled without compensation to the holders, and as of December 31, 2005 we do not have a share option program in place. Our Board of Directors is authorized until June 2007 to issue 6,000,000 shares with a par value of NOK 10 per share.

Compensation of Directors

For the year ended December 31, 2005, the aggregate amount we paid for compensation to our directors as a group for services in all capacities during 2005 was $548,705. This amount includes compensation paid to all persons who served as directors during any period of 2005. None of our directors has any contract with us providing benefits upon termination of service.

Compensation of Executive Officers

During the year ended December 31, 2005, we paid compensation to our president and chief executive officer and other executive officers as follows:

		Year Ended December 31, 2005	
Name:	Position:	Fixed Salary and Other Compensation	Bonus(a)
		(In dollars)	
Svein Rennemo	President and Chief Executive Officer	$607,454	$177,440
Gottfred Langseth	Senior Vice President and Chief Financial Officer	355,313	82,129
Rune Eng	President — Marine Geophysical	413,333	74,876
Eric Wersich	President — Onshore	262,350	85,259
Espen Klitzing	President — Production, from November 2005	54,597	—
Sverre Skogen	President — Production, through October 2005	189,731	72,751

(a) 2004 bonus paid during 2005, including share purchase bonus.

Included in Svein Rennemo's fixed salary and other compensation is an annual pension benefit compensation of $38,998 (equivalent to NOK 250,000). Bonus includes $126,743 (equivalent to NOK 812,500) in cash bonus and $50,697 (equivalent to NOK 325,000) of share purchase bonus. We also paid $57,565 in minimum requirement to a defined benefit plan (for the years 2003, 2004 and 2005). Please read note 22 of the notes to our consolidated financial statements in Item 18 of this annual report for additional information relating to our defined benefit plan. Starting in 2006, Mr. Rennemo's fixed annual pension benefit compensation, included in fixed salary, was reduced to approximately $30,000 (equivalent to NOK 200,000).

Under our 2005 bonus incentive plan, our President and chief executive officer is entitled to a cash bonus of up to 50% of annual base salary and a share purchase bonus of up to 30% of annual base salary. On the basis of achievement of certain group and financial performance indicators, the Board of Directors determined that our chief executive officer was entitled to a cash bonus of $240,246 (equivalent to NOK 1,625,000) and a share purchase bonus of $144,147 (equivalent to NOK 975,000) for 2005. The estimated bonus was accrued as of December 31, 2005. The net share purchase bonus amount, after withholding taxes, must be used to buy our shares at prevailing market prices and held for a minimum of three years. Our chief executive officer held 11,544 shares of our company as of March 31, 2006. For additional information regarding Mr. Rennemo's employment arrangements, please read "Additional Information — Material Contracts — Employment Contract with CEO and CEO Bonus Scheme" in Item 10 of this annual report.

The aggregate benefits paid to the various defined benefit plans for executive officers, excluding the chief executive officer, as a group for 2005 was $25,373. As of March 31, 2006, executive officers, excluding the chief executive officer, owned a total of 7,915 shares. None of the executive officers held any share options in PGS.

For 2005 the Board of Directors established a performance bonus incentive plan for the executive officers similar to that for the chief executive officer. Under the plan, executive officers listed above who were employed by us during 2005 and remain employed as of December 2005 are entitled to a cash bonus of up to 40% of annual base salary and a share purchase bonus of up to 20% of annual base salary. Within these limits, bonuses were finally determined on the basis of achievement of financial and non-financial performance targets. Any amounts received as a share purchase bonus, on a net basis (after withholding tax), must be used to buy shares of our company at prevailing market prices and held for a minimum of three years. The Board determined that the bonus under the scheme for these executives for 2005 would be $566,719 in the aggregate, as presented in the table below, which was accrued at December 31, 2005.

Name:	Position:	Accrued 2005 Bonus at December 31, 2005 (a)
		(In dollars)
Gottfred Langseth	Senior Vice President and Chief Financial Officer	$186,283
Rune Eng	President — Marine Geophysical	212,895
Eric Wersich	President — Onshore	74,400
Espen Klitzing	President — Production, from November 2005	93,141

(a) Bonus earned and accrued in 2005, including share purchase bonus.

For the year ended December 31, 2005, we also had a cash bonus and share purchase bonus plan for another group of approximately 120 key employees that is similar to the plan described above for our executive officers, except that the bonus amounts and percentages for each employee are generally smaller. We have established bonus plans for 2006 with the same principles as the 2005 bonus plans, covering our executive officers and additionally approximately 160 key employees. We currently are not authorized to issue any stock options or other stock-based awards under any stock option plan or similar plan or arrangement for involving employees in the capital of our company.

Employees

The following table presents information about the number of our employees as of the end of each of the last three years:

	At December 31,		
	2005	2004	2003
Marine Geophysical	1,192	1,115	1,143
Onshore(a)	3,237	1,011	1,479
Production	512	501	515
Pertra (sold March 2005)	—	16	5
Global services/Reservoir/Corporate	189	256	235
Total	5,130	2,899	3,377

(a) Onshore includes crew hired for specific time periods (generally the length of the respective project) totaling 3,064; 891 and 1,384 crew members as of December 31, 2005, 2004 and 2003, respectively. The increase in the number of our Onshore employees in 2005, as compared with 2004, was primarily attributable to our hiring of local workers to staff seismic crews in connection with a single onshore project in Bangladesh.

We have not experienced any material work stoppages related to union activities during 2005 and consider our relations with our employees to be good.

ITEM 7. *Major Shareholders and Related Party Transactions*

As of March 31, 2006, Umoe Industri AS and Agra AS collectively beneficially own 3,087,332 shares, or 5.2% of our outstanding shares. Mr. Jens Ulltveit-Moe, founder, chief executive officer and president of Umoe Group, the parent company of Umoe Industri AS and Agra AS, serves as chairman of our Board of Directors. In December 2004, Mr. Ulltveit-Moe reduced his percentage of ownership from 9.6% to 5.1%. Please read Item 6 of this annual report for additional information regarding Mr. Ulltveit-Moe.

Based on a Schedule 13G filed with Securities and Exchange Commission on February 14, 2006, FMR Corp. beneficially owns and has sole dispositive power over 5,956,015 shares, or 9.9% of our outstanding shares, and has sole voting power with respect to 3,847,908 shares. Members of the family of Mr. Edward C. Johnson, III, chairman of FMR Corp., own approximately 49% of the outstanding voting stock of FMR Corp., and may be deemed to be part of a controlling group with respect to FMR Corp. Fidelity Management & Research Company ("Fidelity"), a wholly owned subsidiary of FMR Corp., beneficially owns 2,131,957 shares, or 3.6% of our outstanding shares. Fidelity acts as an investment advisor to various registered investment companies (the "Fidelity Funds"). Each of Mr. Johnson and FMR Corp., through the control of Fidelity, has sole power to dispose of 2,131,957 shares owned by the Fidelity Funds. Each of the Fidelity Funds' boards of trustees has voting power over the shares held by each fund. Fidelity International Limited ("FIL"), a company of which Mr. Johnson is the chairman, beneficially owns 3,824,058 shares, or 6.4% of our outstanding shares. FMR Corp. disclaims beneficial ownership of shares owned by FIL.

Our shareholders that are the beneficial owners of 5% or more of our ordinary shares do not have different voting rights than our other shareholders.

As of March 10, 2006, there were 32 record holders of ADSs representing 7,897,983 shares, of which 26 had registered addresses in the United States. These 26 United States record holders held ADSs representing 7,897,820 shares, which represented approximately 13% of the total number of our shares outstanding as of that date.

Based upon information available from Verdipapirsentralen, the Norwegian centralized registry of securities, as of December 31, 2005, there were 60,000,000 ordinary shares outstanding (including shares represented by ADSs) held by 2,877 record holders, of which 114 had registered addresses in the United States and 2,406 had registered addresses in Norway. The United States holdings represented 17,751,361 shares, or approximately 30% of the total number of our shares outstanding as of that date. For this purpose, Citibank, N.A., in its capacity as the depositary for our ADSs, represents one record holder of shares. The above numbers may not be representative of the actual number of United States beneficial holders or of shares beneficially held by U.S. persons. The Norwegian holdings represented 12,034,068 shares, or approximately 20% of the total number of our shares outstanding as of that date.

Please read note 25 of the notes to our consolidated financial statements included in Item 18 of this annual report for information regarding our related-party transactions.

ITEM 8. *Financial Information*

Financial Statements

Please read Item 18 of this annual report.

Legal Proceedings

From time to time, we are involved in or threatened with various legal proceedings arising in the ordinary course of business. See "Key Information — Risk Factors — Other Risk Factors — We are a multinational organization faced with increasingly complex tax issues in many jurisdictions, and we could be obligated to pay additional taxes in various jurisdictions" in Item 3 of this annual report. We have identified issues in several jurisdictions that could eventually make us liable to pay material amounts in taxes relating to prior years. Additional issues that we are not currently aware of may be identified in the future. We do not believe that we are engaged in, or have recently been engaged in, any additional legal or arbitration proceedings that could have, or have had, a significant effect on our financial position or results of operations. We are not engaged in any material proceeding that involves any director, member of senior management or affiliate as an adverse party to us.

Dividend Restrictions

Our ability to meet parent company-level payment obligations depends upon dividends, distributions, advances and other inter-company transfers from our subsidiaries.

Under Norwegian law, dividends in cash or in-kind as a distribution of our profit and the profits of our Norwegian subsidiaries are only payable annually, and any proposal by the Board of Directors to pay a dividend must be recommended by the directors and approved by the shareholders at a general meeting. The shareholders may vote to reduce, but not to increase, the dividends proposed. Dividends in cash or in-kind are payable only out of the following items, as computed for Petroleum Geo-Services ASA (parent company) based on its unconsolidated financial statements in accordance with Norwegian GAAP:

- the annual profit according to the income statement for the last financial year;
- other unrestricted equity, after deduction of:
- accumulated losses;
- the book value of research and development, goodwill and net deferred tax assets recorded on the balance sheet;
- the aggregate nominal value of treasury shares held by or pledged to us;
- the value of such credit or security in favor of our shareholders, directors or management that can be granted only out of our unrestricted equity; and
- any part of the annual profit that, according to law or our articles of association and the articles of each of our Norwegian subsidiaries, must be allocated to restricted funds.

Neither we nor our Norwegian subsidiaries can declare dividends if the equity, according to our unconsolidated Norwegian GAAP balance sheets, amounts to less than 10% of the balance sheet, or dividends in excess of an amount that is compatible with good and careful business practice with due regard to any losses that may have occurred after the last balance sheet date or that may be expected to occur. The ability of our foreign subsidiaries to transfer funds to the parent company may be restricted by exchange, statutory or other limitations. In addition, our $1 billion credit facility restricts our ability to pay dividends or make similar distributions.

At present, we do not currently expect to pay ordinary dividends to shareholders. In general, any future dividend will be subject to determination based on our results of operations and financial condition, our future business prospects, any applicable legal or contractual restrictions and other factors that the Board of Directors considers relevant.

As described above under "Information on the Company — Proposed Separation of the Geophysical and Production Businesses" in Item 4 of this annual report, the Board of Directors has proposed to our shareholders that we separate our geophysical and production businesses into two independently listed companies. This separation would be accomplished through a demerger under Norwegian law of our production business. If the demerger is consummated as planned, it will significantly change the nature of our business and our capital structure. The geophysical industry remains cyclical. We are therefore targeting strong financial flexibility going forward in a business climate where capturing attractive growth opportunities will be key to shareholder value creation. This overall direction will also guide the Board in formulating and recommending an appropriate dividend policy for 2006 and later years.

Significant Changes

Except as disclosed in this annual report, no significant changes have occurred since the date of our 2005 annual financial statements.

ITEM 9. *The Offer and Listing*

Listing Details

Our ordinary shares are listed on the Oslo Stock Exchange ("OSE") and trade on that exchange under the symbol "PGS." These shares are not publicly traded outside Norway.

We also have American Depositary Shares ("ADSs") that are traded on the New York Stock Exchange ("NYSE") under the symbol "PGS". Each ADS represents one share. Citibank, N.A. serves as the depositary for the ADSs. PGS listed the ADSs on the NYSE in April 1997. On February 26, 2003, the NYSE informed us that our ADSs were suspended from the NYSE and that it would commence proceedings with the U.S. Securities and Exchange Commission to delist the securities. Our ADSs were then traded over-the-counter ("OTC") and were quoted on the Pink Sheets under the ticker symbol "PGOGY."

On November 6, 2003, subsequent to our emergence from Chapter 11, our new ordinary shares began trading on the Oslo Stock Exchange and our new ADSs began trading on the OTC Pink Sheets under the symbol "PGEOY."

On December 17, 2004, our ADSs were relisted on the NYSE and began trading under the symbol "PGS."

American Depositary Shares

We have presented in the table below, for the periods indicated, the reported high and low closing prices for our ADSs on the New York Stock Exchange and the Pink Sheets, as applicable. Upon emergence from Chapter 11 proceedings and consummation of our financial restructuring in November 2003, the pre-restructuring shareholders received one post-restructuring share per 129 old shares, in addition to the right to subscribe for new shares in a rights offering. The new shares began trading on the Pink Sheets on November 6, 2003. The old shares were cancelled. In June 2005 we split our shares three for one. The share prices in the table below have been adjusted for this three-for-one split.

	Price per ADS	
Calendar Period	High	Low
2001	$ 4.88	$ 1.67
2002	2.63	0.12
2003 (through February 26)	0.16	0.10
2003 (February 26 — November 5)	0.50	0.03
2003 (from November 6)	14.33	10.93
2004 (through December 16)	20.75	11.17
2004 (from December 17)	20.69	19.33
2005	31.82	18.91

Calendar Period	Price per ADS High	Price per ADS Low
First Quarter 2004	$17.07	$12.68
Second Quarter 2004	16.00	11.17
Third Quarter 2004	16.17	12.25
Fourth Quarter 2004 (through December 16)	20.75	12.50
Fourth Quarter 2004 (from December 17)	20.69	19.33
First Quarter 2005	24.92	19.83
Second Quarter 2005	25.25	18.91
Third Quarter 2005	31.82	24.00
Fourth Quarter 2005	31.60	24.40
First Quarter 2006	48.99	32.28

Calendar Period	Price per ADS High	Price per ADS Low
October 2005	$31.60	$24.50
November 2005	28.30	24.40
December 2005	31.05	28.57
January 2006	36.30	32.28
February 2006	40.53	33.94
March 2006	48.99	40.45

Shares

We have presented in the table below, for the periods indicated, the reported high and low closing prices for our shares on the Oslo Stock Exchange. On November 6, 2003, upon emergence from Chapter 11 proceedings and consummation of our financial restructuring, the pre-restructuring shareholders received one new share per 129 old shares, in addition to the right to subscribe for new shares in a rights offering. In June 2005 we split our shares three for one. The share prices in the table below have been adjusted for this three-for-one split.

Calendar Period	Price per Share High	Price per Share Low
2001	NOK 41.5	NOK 14.7
2002	23.3	0.9
2003 (through November 5)	3.6	0.4
2003 (from November 6)	105.0	71.0
2004	128.3	81.7
2005	211.0	120.7

Calendar Period	Price per Share High	Price per Share Low
First Quarter 2004	NOK 121.7	NOK 87.3
Second Quarter 2004	112.3	81.7
Third Quarter 2004	111.0	82.8
Fourth Quarter 2004	128.3	96.3
First Quarter 2005	161.7	124.3
Second Quarter 2005	164.0	120.7
Third Quarter 2005	208.5	156.5
Fourth Quarter 2005	211.0	157.0
First Quarter 2006	326.5	214.5

Calendar Period	Price per Share High	Price per Share Low
October 2005	NOK 211.0	NOK 157.0
November 2005	191.0	160.5
December 2005	210.0	195.0
January 2006	244.5	214.5
February 2006	275.5	230.0
March 2006	326.5	274.5

ITEM 10. *Additional Information*

Description of Share Capital

We have summarized below material information about our share capital, our articles of association and provisions of Norwegian law that apply to our share capital. This summary is not complete. For more information about our share capital, we encourage you to read our articles of association, which we have filed as an exhibit to this annual report.

Organization, Register and Purpose

We are a public limited liability company organized under the laws of the Kingdom of Norway. Our registration number with the Norwegian Company Registry is 916235291. As set forth in Section 2 of our articles of association, our business is to provide services to and participate and invest in energy related businesses.

Voting Rights

As a general rule, our shareholders can take action under Norwegian law or our articles of association by a simple majority of votes cast at a general meeting of shareholders. Each ordinary share carries one vote. Amendments to our articles of association, however, including any amendment increasing our share capital or altering the rights and preferences of any share or class of shares, require the approval of at least two-thirds of the votes cast and at least two-thirds of the share capital represented at a shareholders' meeting, whether or not holders of the share capital are entitled to vote. In some cases, a stricter voting requirement may apply.

To vote at an annual or extraordinary general meeting, a shareholder must be registered as a holder of title to the shares to be voted in our share register maintained at Verdipapirsentralen ("VPS"), the Norwegian centralized registry of securities, not later than at the date of the general meeting. Shareholders who intend to participate in a general meeting in person or by proxy must notify us by the date stated in the notice convening the meeting, which date must be at least two business days before the date of the meeting.

Under our articles of association, the beneficial owner of shares registered in VPS through a custodian approved by the Norwegian authorities may vote the shares covered by the custodial arrangement if:

- the beneficial owner provides us, no later than two business days prior to the meeting, with its name, address and a confirmation from the custodian that the holder is the beneficial owner of the shares held in custody; and
- our Board of Directors does not disapprove the beneficial ownership after receipt of notification as described below under "— VPS and Transfer of Shares."

As an alternative to the voting procedure for beneficial owners described above, under Norwegian law, owners of ADSs representing shares can vote by surrendering their American Depositary Receipts, or ADRs, evidencing ADSs to the custodian and having title to the related shares registered in our share register maintained at the VPS prior to the meeting.

Our annual general meeting of shareholders is held each year before the end of June. Norwegian law requires that written notice of general meetings be sent to shareholders whose addresses are known at least two weeks prior to the date of the meeting. Under our articles of association, we may call general meetings on four weeks' written notice. A shareholder may vote by proxy. Although Norwegian law does not require us to send proxy forms to our shareholders for general meetings, we normally include a proxy form with the meeting notice. Any shareholder may demand that a specific issue be placed as an item on the agenda for any general meeting provided that we are notified in time for such item to be included in the meeting notice.

Extraordinary general meetings of shareholders may be held:

- whenever our Board of Directors considers it necessary;
- at the request of our auditor; or
- at the request of shareholders representing at least 5% of our share capital.

Extraordinary general meetings of shareholders may be called with two weeks written notice when called at the written request of our auditor or at the request of shareholders representing at least 5% of our share capital. The request must name the matters to be considered. The extraordinary general meeting must be convened within one month of the date of the request. Other than approval of the annual accounts and declaration of dividends, any matter that may be raised at an annual general meeting may also be raised at an extraordinary general meeting.

Norwegian law prohibits the general meeting or the Board of Directors of any other person representing us from taking any action that may give a shareholder an unreasonable benefit at the expense of other shareholders or us.

Restrictions on Ownership of Shares

At present, there is no limitation on ownership of shares by persons who are not Norwegian.

Share Register

Under Norwegian law, shares are registered in the name of the owner of the shares. As a general rule, there are no arrangements for nominee registration. However, shares may be registered in the VPS, described below under "— VPS and Transfer of Shares," by a fund manager (bank or other nominee) approved by the Norwegian Ministry of Finance, as the nominee of foreign shareholders. An approved and registered nominee has a duty to provide information on demand about beneficial shareholders to the company and to the Norwegian authorities. In the case of registration by nominees, registration with the VPS must show that the registered owner is a nominee. Registration must include the nominee's name, address and number of shares that are the subject of the nomination agreement. A registered nominee has the right to receive dividends and other distributions but cannot vote at general meetings on behalf of the beneficial owners. Beneficial owners must register with the VPS or provide other proof of their acquisition of the shares in order to vote at general meetings.

VPS and Transfer of Shares

Norway has a paperless, centralized registry of shares and other securities, VPS. We and all other Norwegian public companies are obligated to register our shares in VPS. Share certificates are not used. VPS is a computerized bookkeeping system operated by an independent body in which the ownership of and all transactions relating to Norwegian listed shares must be recorded. Our share register is operated through VPS under VPS number 000-4225004.

All transactions relating to securities registered with VPS are made through computerized book entries. VPS confirms each entry by sending a transcript to the registered shareholder irrespective of any beneficial ownership. To effect an entry, the individual shareholder must establish a share account with a Norwegian account agent. Norwegian banks, the Bank of Norway, authorized securities brokers in Norway and Norwegian branches of credit institutions established within the European Economic Area are allowed to act as agents. If the shareholder does not establish an account, the issuing company will appoint an agent on the shareholder's behalf.

A VPS entry represents prima facie evidence in determining the legal rights of a registered holder of a security against the issuing company or a third party claiming an interest in the security.

VPS is strictly liable for any loss resulting from an error in connection with registering, altering or canceling a right, except in the event of contributory negligence, in which event compensation owed by the VPS may be reduced or withdrawn.

Under Norwegian law, a transferor must register immediately with VPS any acquisition or other transfer of shares. A person to whom shares have been transferred or assigned may exercise the rights of a shareholder for those shares only if:

- the transfer or assignment has been registered or that person has reported and shown evidence to us of the share acquisition; and
- the acquisition is not prevented by law, our articles of association or otherwise.

Our articles of association provide that our shares are freely transferable, except that an acquisition by assignment is subject to approval by our board of directors, which cannot be withheld without reasonable grounds. This provision could operate to prevent or impede a change in control of our company.

ADSs and Transfer and Voting

Our shareholders may choose to hold our shares as ADSs, in which case the shares are represented by ADRs. ADSs may be transferred, at the option of the holder, by transferring the related ADRs, or by requesting that the underlying shares be issued to the holder, who then transfers them to the transferee. Holders of ADSs may vote the underlying shares by:

- requesting that the shares be certificated by having them transferred to a VPS account in the name of the holder;
- providing name and address information, and a confirmation from Citibank N.A., as depositary for the ADSs, to the effect that the holder is the beneficial owner of the underlying shares; or
- authorizing Citibank N.A. to vote the ADSs on the holder's behalf.

Disclosure Obligations

Under Norwegian law, a person, entity or group acting in concert must notify the Oslo Stock Exchange immediately of an acquisition or disposition of shares or rights to shares and of its aggregate holdings of shares or rights to shares following the acquisition or disposition, if the acquisition or disposition results in the holder's aggregate beneficial ownership of shares or rights to shares reaching, exceeding or falling below thresholds of $^1/_{20}$, $^1/_{10}$, $^1/_5$, $^1/_3$, $^1/_2$, $^2/_3$ or $^9/_{10}$ of the total number of shares outstanding or of the outstanding voting rights. A corresponding disclosure obligation applies to holders of ADRs.

Additional Issuances and Preemptive Rights

To issue additional shares, including bonus issues (share dividends), we must amend our articles of association. This amendment requires the same shareholder vote as other amendments to our articles of association, which is at least two-thirds of the votes cast and at least two-thirds of the share capital represented at the meeting. Our shareholders also must approve by the same vote the issuance of loans convertible into shares or warrants to purchase shares. At a general meeting, the shareholders may by the same majority authorize our Board of Directors to issue:

- an aggregate number of shares not exceeding 50% of the number of shares outstanding at the time of the general meeting; and
- loans convertible into an aggregate number of shares not exceeding 50% of the number of shares outstanding at the time of the general meeting.

The duration of these authorizations cannot exceed two years.

Under Norwegian law, shareholders have preemptive rights to subscribe for and be allotted new shares that we issue. Shareholders may waive those preemptive rights in a general meeting by the same vote required to approve amendments to our articles of association. A waiver of shareholders' preemptive rights for bonus issues (share dividends) must be approved by the holders of all shares outstanding.

If we issue shares upon the exercise of preemptive rights to holders who are citizens or residents of the United States, we may be required to file a registration statement in the United States under U.S. securities laws. If we decide not to file a registration statement, those U.S. holders would not be able to exercise their preemptive rights and would be required to sell them to Norwegian persons or other non-U.S. holders to realize the value of the rights.

Under Norwegian law and with shareholder approval, we may distribute bonus issues (share dividends) of our shares from amounts:

- that we could otherwise distribute as dividends; or
- that we may create by transferring funds from our share premium reserve discussed below under "— Dividends and Legal Reserves" to share capital.

We can implement bonus issues (share dividends) either by issuing shares or by increasing the par value of the shares outstanding.

At our Annual General Meeting in June 2005, our Board of Directors was authorized to increase our share capital by up to 6,000,000 shares through one or more subscriptions. The authorization is valid until June 2007. The authorization was unused as of December 31, 2005.

Dividends and Legal Reserves

Please read "Financial Information — Dividend Restrictions" in Item 8 of this annual report for information regarding our ability to pay dividends or distribute profits to our shareholders, and whether we intend to pay dividends. We hereby incorporate information called for by this Item 10 by reference to the information under that caption.

Under Norwegian law, we are required to maintain reserves that are adequate in light of our activities and related risks. We must allocate to the share premium (restricted) reserve any premium paid to us for the subscription of new shares.

Examination of PGS and its Accounts

Under Norwegian law, any shareholder may request that Norwegian courts order an examination of our company and accounts if such request is approved by 10% or more of the aggregate share capital represented at any general meeting.

Rights upon Winding-Up

A Norwegian company may be wound up by a resolution of the company in a general meeting passed by at least two-thirds of the aggregate votes cast by its voting shares and by at least two-thirds of the aggregate share capital represented at the meeting irrespective of class. The shares rank pari passu in the event of a return of capital by the company on a winding-up or otherwise.

Interested Director Transactions

Under Norwegian law, a director may not participate in a discussion or decision of any matter in which the director or any related person of the director has a significant personal or financial special interest. In addition, under Norwegian law, a director may not participate in a discussion or decision involving any proposed loan or other credit to the director or pledge of security for the director's debt.

Other Provisions Relating to Directors

Each of our directors stands for election at our annual general meeting, and our directors do not serve staggered terms. There is no cumulative voting for directors.

Under Norwegian law, any compensation payable to a director must be determined by the shareholders in a general meeting. There is no mandatory retirement provision under Norwegian law or our articles of association, nor is there a requirement that our directors own our shares or ADSs.

Mandatory Bid Requirement

Norwegian statutory law requires any person, entity, family group or other group acting in concert that acquires shares (including ADSs) representing more than 40% of the voting rights of a Norwegian company listed on the Oslo Stock Exchange to notify the Oslo Stock Exchange immediately and to make a general offer to acquire all the outstanding share capital of that company. Such offer must be made no later than four weeks after the obligation is triggered and in the form of an offer document to all shareholders. The offer may not be conditional and is subject to approval by the Oslo Stock Exchange before submission to the shareholders. The offer must be in cash or contain a cash alternative at least equivalent to any other consideration offered. The offering price per share must be the greater of:

- the highest price paid by the offeror for the shares in the six-month period prior to the date the 40% threshold was exceeded; or
- the recorded market price at that date.

If the acquirer acquires, or agrees to acquire, additional shares at a higher price after exceeding the 40% threshold but prior to the expiration of the four-week bid period, the acquirer must restate its bid at that higher price. If a shareholder who is required to make a mandatory bid fails to do so, the shareholder must within four weeks dispose of sufficient shares so that the obligation ceases to apply. Otherwise, the Oslo Stock Exchange may cause the shares exceeding the 40% limit to be sold by public auction.

During the time the mandatory bid requirement is in force, a shareholder failing to make the required offer may not vote or exercise any rights of share ownership other than the right to receive dividends and preferential rights relating to a share capital increase, unless a majority of the remaining shareholders approve. In addition, the Oslo Stock Exchange may impose a daily fine upon a shareholder who fails to make the required offer.

Citibank, N.A., the depositary for our ADSs, has qualified and been recognized as a custodian of the shares in Norway. As a result, it is exempt from the mandatory bid requirement.

Sale of All or Substantial Part of Our Property or Assets

There is no general requirement under Norwegian law that the sale, lease or exchange of all or substantially all of the property or assets of a Norwegian company requires shareholder approval in addition to the approval of the Board of Directors, unless such a transaction would imply that the business and purpose of the company as described in its articles of association would be amended, in which event the approval of at least two-thirds of the votes cast and at least two-thirds of the share capital represented at the meeting is required.

Compulsory Acquisition (Squeeze Out/Sell Out Right)

Under Norwegian law, if a shareholder, directly or indirectly, acquires shares of a Norwegian company representing more than 90% of the total number of shares outstanding or of the outstanding voting rights, then such majority shareholder has the right (and each remaining minority shareholder of the company has the right to require such majority shareholder) to effect a compulsory acquisition for cash of any shares not already owned by such majority shareholder. Under such a compulsory acquisition, the majority shareholder becomes the owner of the acquired shares with immediate effect. Upon effecting the compulsory acquisition, the majority shareholder would be required to offer the minority shareholders a specific price per share, the determination of which price would be at the discretion of the majority shareholder. If any minority shareholder does not accept the offered price, such minority shareholder may, within a specified deadline of not less than two months, request that the price be set by the Norwegian courts. Generally, the cost of any such court procedure would be borne by the majority shareholder, and the courts would have full discretion in respect of the valuation of the shares for the compulsory acquisition. In the absence of such a request or other objection to the price being offered by the majority shareholder, the minority shareholders would be deemed to have accepted the offered price after the expiration of a two-month period.

Exchange Controls and Other Limitations Affecting Security Holders

Under Norwegian foreign currency exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior governmental approval except for the physical transfer of payments in currency, which is restricted to licensed banks. As a result, a non-Norwegian resident may receive dividend, principal and interest payments on our securities without a Norwegian exchange control consent, but the payments must be made through a licensed bank.

There are no limitations imposed by Norwegian law or our articles of association on the right to hold or vote shares that apply differently to non-Norwegian owners than to Norwegian owners.

Material Contracts

We provide below a summary of material contracts that we have entered into in the last two years, other than contracts entered into in the ordinary course of our business. The descriptions below are qualified in their entirety by reference to the agreements being described, which are listed in Item 19 of this annual report.

Employment Contract with CEO and CEO Bonus Scheme

On January 26, 2006, we entered into a new employment agreement with Svein Rennemo, our Chief Executive Officer. The new agreement replaced Mr. Rennemo's 2002 employment agreement.

The new employment agreement provides (i) for an annual salary in 2006 of NOK 3,250,000, which salary is subject to annual review, (ii) for a car allowance of NOK 225,000, (iii) that Mr. Rennemo may participate in (A) our group life, accident and travel insurance and other personnel insurance that we provide, and (B) our CEO bonus arrangement and (iv) for vacation and holiday allowance/pay. As pension compensation, we are obligated (1) to pay to Mr. Rennemo NOK 200,000 annually as compensation for lack of an executive pension arrangement, (2) commencing January 1, 2006, to make a contribution for the benefit of Mr. Rennemo to the general pension insurance scheme (as applicable to all Norwegian employees), and (3) make a lump sum payment of NOK 361,058 to the general pension insurance scheme (as applicable to all Norwegian employees) to compensate for the lack of premium payments from the commencement of Mr. Rennemo's employment in 2002 through 2005.

Mr. Rennemo's employment will terminate at age 60, unless we otherwise agree in writing with Mr. Rennemo. In addition, both we and Mr. Rennemo can terminate the employment agreement with 12 months notice or, if the period of time remaining prior to Mr. Rennemo's 60^{th} birthday is less, notice of such lesser period of time. The employment agreement may also be terminated by us for breach of contract by Mr. Rennemo.

In 2004, we also instituted our 2004 CEO Bonus Scheme, pursuant to which our CEO is eligible for a cash bonus of up to 50% of his base salary and a share bonus of up to 30% of his base salary. The maximum amount of any cash or share bonus is based on the achievement by PGS of certain specified financial goals. The actual amount of any cash or share bonus is based on the achievement by PGS and the CEO of certain specified goals. The net amount, after withholding taxes, of any share bonus must be invested in our shares. Shares purchased with this bonus must be held for at least three years, unless our Board of Directors consents to an earlier sale.

December 2005 Credit Facility

On December 19, 2005, we and certain of our affiliates entered into a $1 billion senior secured credit facility with the lenders named therein. Please see "Operating and Financial Review and Prospects — 2005 Refinancing" and "— Liquidity and Capital Resources — Sources of Liquidity — Capital Resources" in Item 5 of this annual report for a description of this credit facility.

Sale of Pertra

On March 1, 2005, we sold Pertra to Talisman for a sales price of approximately $155 million. Please read "Information on the Company — Sale of Our Oil and Natural Gas Subsidiary Pertra" in Item 4 and note 24 of the consolidated financial statements included in Item 18 of this annual report for a description of this transaction.

Taxation

General

The following discussion generally summarizes the principal Norwegian and U.S. federal income tax consequences of the ownership and disposition of our ADRs, which evidence our ADSs, and our shares to holders of ADRs and shares who are residents of the United States or otherwise subject to U.S. federal income taxation on a net income basis for ADRs and shares and who are not residents of Norway ("U.S. Holders"). The summary applies only to holders who will hold ADRs or shares as capital assets and does not address certain classes of holders, such as holders who own, directly or indirectly, at least 10% of our outstanding shares, which may be subject to special rules. Because it is a general summary, prospective purchasers of ADRs or shares who would be U.S. Holders are advised to consult their own tax advisors about the U.S. federal, state and local tax consequences and the Norwegian tax consequences of the ownership and disposition of ADRs and shares that are applicable in their particular tax situations, including the effects of recent and possible future changes in the applicable tax laws.

The summaries of U.S. and Norwegian tax laws provided below are based on the tax laws of the United States and Norway, the income tax convention between the United States and Norway (the "Convention") and interpretations by the relevant tax authorities that are in effect as of the date of this annual report and are subject to any changes that may occur after that date (possibly with retroactive effect).

For U.S. and Norwegian tax purposes, U.S. Holders of ADRs will be treated as the owners of the shares represented by the ADRs. Unless we have otherwise stated below, the Norwegian tax consequences and the U.S. federal income tax consequences discussed below apply equally to U.S. Holders of ADRs and U.S. Holders of shares.

We believe, and this discussion assumes, that we are not and have never been a passive foreign investment company as that term is defined in the U.S. Internal Revenue Code of 1986, as amended (the "Code").

Taxation of Dividends

Under Norwegian tax law, dividends paid to foreign shareholders of Norwegian corporations are, unless otherwise provided for in an applicable tax treaty, subject to a withholding tax in Norway of 25%. Under the Convention, the maximum rate of withholding tax on dividends paid by a Norwegian corporation to a "resident of the United States," as defined in the Convention, is 15%. The 15% withholding rate will apply to any dividends paid on our shares held directly by U.S. Holders who properly demonstrate to us and to the Norwegian tax authorities that they are entitled to the benefits of the Convention. Dividends paid to Citibank, as depositary, will be subject to withholding at the 25% rate. U.S. Holders of ADRs who believe they are entitled to the benefits of the Convention may apply to the Norwegian tax authorities for a refund of amounts withheld in excess of 15%. The application is to be filed with the Norwegian Central Office — Foreign Tax Affairs. There is some uncertainty, however, as to whether and when such a refund may be obtained.

We intend to file any reports with the Norwegian authorities or agencies necessary to obtain the benefits of the Convention for those entitled to them. We will exercise our right under the deposit agreement to reasonably request from Citibank such information from its records that will enable us to file the reports.

If, however, the recipient of a dividend is determined to be engaged in a business activity taxable in Norway and our shares or ADSs with respect to which the dividend is paid are effectively connected with that activity, then the amount distributed to the U.S. Holder will be treated as taxable domestic dividend income in Norway, subject to the provisions of the Convention, where applicable. After the amendments to the Norwegian tax law, the dividend could potentially be exempted from taxation in Norway if the business activity in Norway is owned by a corporate entity in the United States, but the legal situation is unclear. Such U.S. Holders should seek further tax advice regarding their tax situation in Norway. Dividends will be taxable if a U.S. holder who is an individual with business activity in Norway owns shares, and our shares or ADSs are effectively connected with that activity. Dividends received by the individual shareholder exceeding a risk-free rate of return are subject to taxation at 28%. The risk-free rate of return is calculated for each individual share on the basis of the cost price (including RISK amount up to 1 January 2006) multiplied with an opportunity rate of interest (risk-free rate of interest after tax).

To the extent paid out of our current or accumulated earnings and profits, distributions made on our shares or ADSs, other than certain distributions of our capital stock or rights to subscribe for shares of our capital stock, will be includible in the income of a U.S. Holder for U.S. federal income tax purposes as ordinary dividend income. In the case of a U.S. Holder of an ADR, such dividend income will be recognized on the date Citibank receives the distribution. Dividends we pay will not be eligible for the dividends-received deduction generally allowed to corporations under the Code. The amount of a dividend distribution for tax purposes will equal the U.S. dollar value of the amount of the distribution in Norwegian kroner (including the amount of Norwegian taxes withheld from the distribution), calculated by reference to the exchange rate in effect on the date of the distribution. Upon the ultimate conversion by Citibank into U.S. dollars of the Norwegian kroner received in a distribution, U.S. Holders of ADRs generally will recognize gain or loss for U.S. federal income tax purposes equal to the difference, if any, between such U.S. dollars and the U.S. dollar value of such Norwegian kroner on the date of the distribution. Such gain or loss will be treated as ordinary income or loss.

For taxable years beginning on or before December 31, 2008, dividend income received by an individual, estate, or trust from a corporation organized in the U.S. or from a "qualified foreign corporation" generally is taxed at the lower rates imposed on long-term capital gains recognized by individuals. The maximum rate of tax for such dividends is 15%.

A non-U.S. corporation is a "qualified foreign corporation" if either (i) its stock with respect to which the dividend is paid is readily tradable on an established securities market in the U.S. or (ii) the corporation is eligible for the benefits of a comprehensive tax treaty with the U.S. that the Internal Revenue Service ("IRS") determines is satisfactory for purposes of the provision reducing the rate of tax on dividends, and that includes an exchange of information program. Our ADSs are readily tradable on an established securities market in the U.S. because they are listed on the NYSE. Moreover, we are eligible for benefits under the Convention, and the IRS has identified the Convention as satisfactory for purposes of the provision reducing the rate of tax on dividends and as including an exchange of information program. Accordingly, U.S. Holders that are individuals, estates, or trusts generally will be eligible for the lower long-term capital gains rates with respect to dividends paid on our shares or ADSs.

A U.S. Holder will not be allowed to benefit from the lower long-term capital gains rates unless the U.S. Holder (i) holds our shares or ADSs for more than 60 days during the 121-day period beginning on the date that is 60 days before the date on which the shares or ADSs become ex-dividend (disregarding any period during which the U.S. Holder has a diminished risk of loss with respect to such shares or ADSs), and (ii) is not under an obligation to make related payments with respect to positions in substantially similar or related property.

Norwegian taxes imposed on dividend distributions on our shares or ADSs generally will be eligible for credit against the U.S. Holder's U.S. federal income taxes. The amount of the Norwegian taxes eligible for this foreign tax credit generally will be equal to the amount of such taxes withheld from the dividend distributions, reduced by the amount of any refunds of such taxes subsequently received. U.S. Holders that are eligible for benefits under the Convention will not be entitled to a foreign tax credit for the amount of any Norwegian taxes withheld in excess of the 15% maximum rate, and with respect to which the holder can obtain a refund from the Norwegian taxing authorities. U.S. Holders that are accrual basis taxpayers generally must translate Norwegian taxes into U.S. dollars at a rate equal to the average exchange rate for the taxable year in which the taxes accrue (except that such a U.S. Holder may elect to translate Norwegian taxes using the exchange rate at the time the taxes are paid if the U.S. Holder's functional currency for tax purposes is not the Norwegian kroner). All U.S. Holders must translate taxable dividend income into U.S. dollars at the spot rate on the date received. This difference in exchange rates may reduce the U.S. dollar value of the credits for Norwegian taxes relative to the U.S. Holder's U.S. federal income tax liability attributable to the dividend.

Under the foreign tax credit limitations of the Code, the foreign tax credit can offset U.S. federal income taxes imposed on foreign-source income but not on U.S.-source income. In addition, foreign taxes imposed on income in certain categories specified in the Code may only be used to offset U.S. taxes on income in the same category. Subject to special rules we describe below, dividends we pay will generally be foreign-source income within either the "passive income" category or the "financial services income" category, depending on the particular U.S. Holder's circumstances. For taxable years beginning after December 31, 2006, dividends that previously would have been "passive income" will generally be "passive category income" and dividends that previously would have been "financial services income" will generally be "general category income."

The Code contains a provision that could, in certain circumstances, cause a portion of the dividends we pay to be treated as U.S.-source income. Even if that provision applied to dividends we pay to a U.S. Holder, because of the source rules contained in the Convention, no portion of such a dividend would be recharacterized as U.S.-source income if the U.S. Holder includes the dividend as a separate category of income for purposes of the foreign tax credit limitation.

If a U.S. Holder that is an individual, estate, or trust is taxed at the lower long-term capital gains rates on dividends we pay, the Code contains a provision that will cause a portion of any dividend eligible for this lower rate to be treated as U.S.-source income. This provision is intended to limit the amount of the Norwegian taxes eligible for the foreign tax credit to the amount of U.S. tax paid by the U.S. Holder at the lower long-term capital gains rates. U.S. Holders are advised to consult their own tax advisors when determining the portion of any dividend that will be treated as U.S.-source income under this provision.

A U.S. Holder will not be allowed to claim foreign tax credits (but would instead be allowed deductions) for foreign taxes withheld on a dividend if the U.S. Holder (i) has not held the shares for at least 16 days in the 31-day period beginning 15 days before the date on which the shares become ex-dividend with respect to such dividend or (ii) is under an obligation to make related payments with respect to positions in property that is substantially similar or related to the shares.

Taxation of Ordinary Dispositions

A U.S. Holder normally is not taxed in Norway on gains from the sale or other disposal of our shares or ADSs. Such a holder may be subject to taxation if the shareholding is effectively connected with a business carried out by the shareholder through a permanent establishment in Norway. In addition, a shareholder may be subject to taxation on gains if the shareholder is an individual who has been a resident of Norway for income tax purposes and the disposal takes place within five years after the calendar year in which the shareholder ceased to be a resident of Norway. The same rules apply to gains realized upon complete liquidation of us or upon redemption of our shares or ADSs. Repayment in connection with a reduction of our share capital by reducing the nominal value of the shares is, however, subject to withholding tax as a dividend distribution, if exceeding paid-in capital.

Under Norwegian tax law, gains from the sale or other disposal of our shares or ADSs by a U.S. Holder is taxable in Norway if the U.S. Holder is engaged in a business activity taxable in Norway and our shares or ADSs are effectively connected with that activity. After the amendments to the Norwegian tax law, such gains could potentially be exempted from taxation when the U.S. Holder with the business activity in Norway is a corporate entity, but the legal situation is far from certain. We recommend that such U.S. Holders seek further tax advice regarding their tax situation in Norway. Losses are deductible if the gains are taxable. Gains from disposal of shares will be taxable as general income at a flat rate of 28% if a U.S. holder who is an individual with business activity in Norway owns the shares, and our shares or ADSs are effectively connected with that activity. Losses on shares are deductible in the shareholders ordinary income. Gain or loss for the individual shareholder is calculated per share, as the difference between the consideration received and the tax basis for the share. The tax basis of each share is based on the shareholder's purchase price for the share. The individual shareholder is entitled to deduct a deemed allowance when calculating taxable gain on sale of shares. The allowance for each share will be equal to the cost price of the share multiplied by a determined risk-free interest rate (see section on dividend taxation above). The tax liability and deductibility apply irrespective of how long the shares have been owned and the number of shares that are sold. If the shares disposed of have been acquired at different times, the shares that were first acquired will be deemed as first sold. Costs incurred in connection with the purchase and sale of shares are deductible in the year of sale, provided that the gain is not exempted from taxation.

A U.S. Holder will recognize capital gain or loss for U.S. federal income tax purposes on a sale or other disposition of our shares or ADSs (or rights to subscribe for our shares), including a sale or other disposition by Citibank of shares (or rights to subscribe for shares) received as dividends on the ADSs, in the same manner as on the sale or other disposition of any other shares held as capital assets (or rights to acquire such shares). Such capital gain or loss will be an amount equal to the difference between the U.S. dollar value of the amount realized and the U.S. Holder's tax basis in the shares. Such capital gain or loss will be long-term if the shares have been held for more than one year. Long-term capital gains recognized by individuals, estates, and trusts are eligible for taxation at rates not in excess of 15%. Any such gain or loss will generally be U.S.-source income or loss.

Regardless of the holding period of the shares or ADSs disposed, if an individual U.S. Holder receives a dividend from us qualifying for the long-term capital gains rates and such dividend constitutes an "extraordinary dividend," and the U.S. Holder subsequently recognizes a loss on the sale or exchange of our shares or ADSs, then the loss will be long-term capital loss to the extent of such "extraordinary dividend." An "extraordinary dividend" for this purpose is a dividend in an amount (i) greater than or equal to 10% of the taxpayer's tax basis (or fair market value as of the day before the ex-dividend date) of the underlying shares or ADSs, aggregating dividends with ex-dividend dates within an 85-day period, or (ii) in excess of 20% of such tax basis (or fair market value as of the day before the ex-dividend date), aggregating dividends with ex-dividend dates within a period of 365 days.

A U.S. Holder will not be allowed to claim foreign tax credits (but would instead be allowed deductions) for foreign taxes imposed on a gross basis on gain with respect to the disposition of our shares or ADSs unless the U.S. Holder (i) holds such shares or ADSs for more than 15 days during the 31-day period beginning on the date that is 15 days before the right to receive payment arises (disregarding any period during which the

U.S. Holder has a diminished risk of loss with respect to such shares or ADSs) and (ii) is not under an obligation to make related payments with respect to positions in substantially similar or related property.

Deposits and withdrawals of our shares in exchange for ADRs will not result in taxable gain or loss for U.S. or Norwegian tax purposes.

U.S. Backup Withholding

Certain payments, including certain dividends and proceeds from sales of stock, may be subject to U.S. "backup withholding" at the current 28% rate if the recipient of such a payment fails to provide an accurate taxpayer identification number or certification of U.S. status or fails to report all interest and dividends required to be shown on its U.S. federal income tax returns, or otherwise fails to establish an exemption from withholding. Any amounts so withheld would be allowed as a credit against the recipient's U.S. federal income tax liability for the year. Dividends we pay to a U.S. Holder generally would be subject to these backup-withholding rules.

Gift and Estate Tax

An individual U.S. Holder will be subject to U.S. gift and estate taxes with respect to our shares in the same manner and to the same extent as with respect to other types of personal property.

Norwegian Transfer Tax

There is no Norwegian stock transfer tax or capital tax upon the acquisition or subsequent disposition of our shares or ADSs.

Norwegian Inheritance Tax

There is no Norwegian inheritance tax or gift tax on our shares or ADSs if the deceased, at the time of death, or the donor at the time the gift is made, is neither a resident nor a national of Norway. If the deceased, at the time of death, is not a resident of Norway, but is a national of Norway, Norwegian inheritance tax will be levied unless inheritance tax or similar tax is levied in the country of residence and the shares are not effectively connected to a permanent establishment in Norway. Under all circumstances, a transfer of shares or ADSs will be subject to gift tax in Norway if the donor at the time of the gift is a Norwegian national.

Norwegian Property Taxes or Similar Taxes

U.S. Holders of our shares or ADSs are not subject to Norwegian property tax or similar taxes (e.g., wealth taxes) with respect to those shares or ADSs, unless the shareholding is effectively connected with a business carried out by the shareholder through a permanent establishment in Norway.

Documents on Display

Please read "Where You Can Find More Information" for information about where you may read and copy documents referred to in this report that we have filed with the SEC.

Subsidiary Information

Please read "Information on the Company — Organizational Structure" in Item 4 of this annual report for information regarding our subsidiaries.

ITEM 11. *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to certain market risks, including adverse changes in interest rates and foreign currency exchange rates, as discussed below. We have entered into the financial instruments described below in order to manage our exposure to these risks, and not for trading purposes.

Interest Rate Risk

We enter into from time to time various financial instruments, such as interest rate swaps, to manage the impact of possible changes in interest rates. Our exposure to changes in interest rates results primarily from (a) outstanding indebtedness under our new $1 billion secured credit facility, which bears interest at a floating rate, (b) short-term indebtedness outstanding from time to time, (c) our capital leases and (d) our UK leases. As of December 31, 2005, we have entered into interest rate swaps relating to $425 million of the $850 million term loan and changed our interest rate exposure from floating to fixed for the $425 million notional amount. In addition, as of that date we had smaller interest rate swaps with the notional amount of $8.6 million, which expired in part in January 2006 and the remaining balance of which we settled in February 2006. The following table presents principal amounts and related average interest rates by year of maturity for our debt obligations as of December 31, 2005:

	2006	2007	2008	2009	2010	Thereafter
			(Dollar amounts in thousands)			
Debt:						
Fixed rate	$11,920	$12,900	$ 14,040	$15,160	$ 21,054	$ 17,480
Average interest rate	8.28%	8.28%	8.28%	8.28%	8.66%	8.28%
Variable rate	$ 9,812	$ 8,500	$ 8,500	$ 8,500	$ 8,500	$807,500
Interest rate	LIBOR*	LIBOR*	LIBOR*	LIBOR*	LIBOR*	LIBOR*
			+ applicable margin**			
Interest swap notional amount			$ 150,000		$ 275,000	
— pays fixed interest rate			4.84%		4.88%	
— receive floating interest rate			3M LIBOR		3M LIBOR	

* 1, 3 or 6 month LIBOR rate

** for applicable margin see Note 16 to our consolidated financial statements included in Item 18 of this annual report.

As of December 31, 2005, we had $851.3 million of interest-bearing debt bearing interest at floating interest rates based on U.S. dollar LIBOR plus a margin. For every one-percentage point increase in the LIBOR, our annual interest expense on such amount of indebtedness will increase by $8.5 million. For every one percentage point increase in the LIBOR, the annual amount of interest we would receive on interest rate swaps in place as of December 31, 2005 would increase by $4.2 million. Based on such amount of indebtedness and interest rate swaps, a one-percentage point increase in LIBOR would result in a net increase in our annual interest costs of approximately $4.3 million.

As of December 31, 2005, we had capital lease obligations of $33.7 million payable through 2008. Interest associated with these capital lease obligations is based on U.S. dollar LIBOR plus a margin. For every one-percentage point increase in LIBOR, our interest expense associated with such capital lease obligations will increase by approximately $0.2 million for 2006.

As described under "Operating and Financial Review and Prospects — Liquidity and Capital Resources — UK Leases" in Item 5 of this annual report, we have entered into certain capital leases in the United Kingdom. The leases are legally defeased because we have made payments to independent third-party banks in consideration for which these banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, we receive rental rebates. If, on the other hand, actual interest rates are less than the assumed interest rates, we are required to pay rentals in excess of the defeased rental payments. For every one percentage point that LIBOR exceeds these assumed interest rates, we are entitled to receive approximately £10.4 million ($18.0 million) in rental rebates. On the other hand, for every one percentage point that LIBOR is less than these assumed interest rates, we are required to pay an additional approximately £10.3 million ($17.9 million) in defeased rental payments. As of December 31, 2005, our balance sheet reflected a liability of approximately £22 million ($38.1 million) for this interest rate exposure. This liability was recorded upon our adoption of fresh start reporting and is amortized systematically based on future rental payments. During 2005, 2004 and 2003, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $7.2 million, $7.2 million and $6.4 million, respectively. The estimated net present value of future payments related to interest rate differential on our UK leases as of December 31, 2005 was $54.5 million based on forward interest rate curves, which is $16.4 million higher than the amount included in accrued liabilities from fresh start reporting. For additional information with respect to our UK leases, please read "Operating and Financial Review and Prospects — Liquidity and Capital Resources — UK Leases" in Item 5 and notes 2 and 20 of the notes to our consolidated financial statements in Item 18 of this annual report.

Foreign Currency Exchange Rate Risk

We conduct business in various currencies including the Bangladeshi taka, Bolivian boliviano, Brazilian real, Indian rupee, Kazakhstan tenge, Mexican peso, Nigerian naira, Saudi riyal, United Arab Emirates dirham, Venezuelan bolivar, British pound and the Norwegian kroner. We are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions in currencies other than the U.S. dollar.

Our cash flows from operations are primarily denominated in U.S. dollars, British pounds and Norwegian kroner. We predominantly sell our products and services in U.S. dollars while some portion of our operating expenses are incurred in British pounds and Norwegian kroner. We therefore typically have higher expenses than revenue denominated in British pounds and Norwegian kroner.

In 2005 we started hedging a portion of our foreign currency exposure related to operating expenses by entering into forward currency exchange contracts. While we enter into these contracts with the purpose of reducing our exposure to changes in exchange rates, we do not account for the contracts as hedges. Consequently, all outstanding forward currency exchange contracts are recorded at estimated fair value using the mid rate and gains and losses are included in other financial items, net. As of December 31, 2005, we had open forward contracts to buy British pounds and Norwegian kroner amounting to approximately $194 million with a fair value of $(7.2) million (loss), which has been recognized in our statements of operations. At December 31, 2004, we did not have any open forward exchange contracts.

If British pounds had appreciated by a further 10% against the U.S. dollar at year-end, the fair value of the forward contracts on buying British pounds would have increased by $5.7 million. A similar 10% appreciation of Norwegian kroner against U.S. dollar would have increased the fair value of the forward contracts on buying Norwegian kroner by $15.2 million.

Substantially all of our debt is denominated in U.S. dollars.

Commodity risk

In the operation of our seismic vessels we use substantial quantity of fuel. We are therefore exposed to changes in fuel prices. Based on our fuel consumption in 2005, if fuel prices were to increase by 10%, our fuel costs would increase by approximately $5 million. We do not hedge this exposure by using derivatives.

ITEM 12. ***Description of Securities Other Than Equity Securities***

Not applicable.

PART II

ITEM 13. ***Defaults, Dividend Arrearages and Delinquencies***

Not applicable.

ITEM 14. ***Material Modifications to the Rights of Security Holders and Use of Proceeds***

Not applicable.

ITEM 15. ***Controls and Procedures***

Beginning in 2004 and through 2005, we have implemented our Sarbanes-Oxley Section 404 readiness project and have significantly improved our internal control environment. In our assessment of our internal control over financial reporting for the period relevant for the preparation of our 2005 financial statements and at December 31, 2005, we have concluded that the material weaknesses identified in connection with the audit of our 2004 financial statements have been remediated. However, two significant control deficiencies remained as of December 31, 2005 regarding the sufficiency of our supervisory review procedures related to income tax provision and regarding timely and sufficiently detailed research and documentation of certain significant accounting issues. Our assessment also identified certain other control deficiencies. We believe that these deficiencies do not represent a material weakness condition, either individually or in aggregate.

In September 2003, our independent registered public accounting firm, Ernst & Young AS ("EY"), identified material weaknesses regarding various elements of our system of internal control over financial reporting. A material weakness condition exists when significant control deficiencies, or a combination of control deficiencies, are present that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

While we made considerable improvement in our internal control over financial reporting during 2004, our assessment of the progress made in addressing the material weaknesses identified in September 2003 indicated that, for the period relevant for the preparation of our 2004 financial statements and at December 31, 2004, significant deficiencies that, in the aggregate, constituted a material weakness continued to exist relating to:

- the U.S. GAAP competency and procedures for timely and complete identification of developments and transactions of a non-routine nature that require specific accounting consideration;
- the sufficiency of supervisory review control activities in parts of our company;
- the sufficiency of procedures to capture and timely and precisely accrue expenses for our Production operations and the vessel operations of Marine Geophysical; and
- the sufficiency of supervisory review and certain other procedures related to income tax provision.

In May 2005, in connection with the audit of our 2004 financial statements under U.S. GAAP, EY confirmed the continuation of these matters that, in the aggregate, they considered to constitute a material weakness.

Acting under the supervision and guidance of our Audit Committee and Board of Directors, our management worked to address these identified material weaknesses and significant deficiencies, including implementing our Sarbanes-Oxley Section 404 readiness project. We recruited additional GAAP expertise to oversee our GAAP compliance and improved procedures for accounting for unusual transactions. We also improved our procedures for capturing and assessing transactions of a non-routine nature and subsequent events; increased focus on timely review, documentation and evaluation of account balances and agreements; and strengthened the procedures for capturing operating expenses and accruals related to our Production operations and vessel operations in Marine Geophysical. To address the deficiency related to reporting of income taxes, we improved the control procedures for income tax accounting, including allocation of responsibilities and strengthened review procedures.

Despite significant improvements in the overall design and controls in relation to the preparation of financial statements, our assessment of the progress made for the period relevant to the 2005 financial reporting indicated that significant control deficiencies remained with respect to the sufficiency of our supervisory review procedures related to income tax provision and, in addition, that not all significant accounting issues were documented and concluded upon timely with sufficient detail and technical reference, specifically regarding pension plan settlements and segment disclosures. A significant deficiency exists when the timeliness and quality control procedures allow more than a remote likelihood that a misstatement of the company's annual financial statements that is more than inconsequential may not be prevented or detected. EY issued a letter dated April 4, 2006 addressing these significant deficiencies.

Our management, with the oversight of our Audit Committee and Board of Directors, is committed to having proper internal control over financial reporting. We believe that the actions already taken will continue to improve our internal control over financial reporting since many of these controls and remedial actions relate to people and processes that require time before they are fully effective. With regards to the significant deficiencies discussed above, we implemented new improved control procedures and hired a technical resource before the 2005 year-end financial reporting. We believe that our procedures have an adequate design quality, and we will implement further personnel training and increased supervision to remediate deficiencies in the operation of the procedures. In addition, management has developed remediation plans to address other identified control deficiencies.

As required by SEC Rule 13a-15(b), we have carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure control and procedures as of December 31, 2005, the end of the period covered by this annual report. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure control and procedures were effective to ensure that information required to be disclosed by us in the reports we file or submit under the U.S. Securities Exchange Act of 1934 was timely recorded, processed, summarized and reported as of December 31, 2005.

Beginning with the year ending December 31, 2006, Section 404 of the Sarbanes-Oxley Act will require us to include an internal control report of management with our annual report on Form 20-F. We expect to continue to make changes in our internal control over financial reporting during our documentation and control evaluation in preparation for compliance with Section 404 of the Sarbanes-Oxley Act. As we implement remaining changes in our internal control and as we address requirements under the Sarbanes-Oxley Act, we could identify additional deficiencies in our system of internal control over financial reporting that will require additional remedial efforts.

Because of the inherent limitations in all control systems, no evaluation of control can provide absolute assurance that all control issues and instances of fraud will be or have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. The design of any system of control also is based in part upon assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, control may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

ITEM 16A. *Audit Committee Financial Expert*

Our Board of Directors has determined that each of Francis Gugen, Anthony Tripodo and Harald Norvik meets the definition of an audit committee financial expert, as that term is defined for purposes of Item 16A of Form 20-F, and that each is independent under applicable provisions of the Securities Exchange Act of 1934 and New York Stock Exchange listing standards.

ITEM 16B. *Code of Ethics*

We have adopted a Code of Conduct that applies to, among others, our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have filed the code as an exhibit to this annual report and posted it under the "About PGS" section of our internet website at *www.pgs.com.*

ITEM 16C. *Principal Accountant Fees and Services*

Under our Audit Committee Charter, the Audit Committee is responsible (subject to approval by the Board of Directors) for:

- pre-approving all auditing services and permitted non-audit services to be provided by our independent registered public accounting firm and observing applicable limitations on engaging the independent registered public accounting firm to perform the specific non-audit services restricted by law or regulations; and
- to the extent it deems necessary or appropriate, retaining and compensating independent legal, accounting or other advisors.

Under our pre-approval policy, the Audit Committee is required to pre-approve all audit, review or attest engagements and permissible non-audit services to be performed by our independent registered public accounting firm, subject to, and in compliance with, the *de minimis* exception for non-audit services described in applicable provisions of the Securities Exchange Act of 1934 and applicable SEC rules. All services provided by EY in 2005 were pre-approved by the Audit Committee.

Aggregate fees through March 31, 2005 for professional services rendered by EY, including reimbursement of out-of-pocket expenses, related to 2005, 2004 and 2003 were as follows:

	Years Ended December 31,		
	2005	2004	2003
	(In thousands)		
Audit fees(a)	$4,112	$4,453	$5,925
Audit-related fees(b)	163	42	114
Fees for tax services(c)	175	134	182
All other fees(d)	4	—	541
Total	$4,454	$4,629	$6,762

(a) Audit fees consisted of fees for audit services, which related to the consolidated audit, statutory audits, accounting consultations, subsidiary audits and related matters, and fees for audit of fresh start reporting. Fees for 2005 are based on estimates as of March 21, 2005. Fees for 2004 and 2003 have been updated to reflect fees incurred after May 3, 2005 related to the 2004 and 2003 audits.

(b) Audit-related fees consisted of fees for agreed upon procedures and other attestation services.

(c) Fees for tax services consisted of fees for tax services, tax filing and compliance and reorganization.

(d) Other fees consisted mainly of fees for assistance in connection with restructuring, refinancing and due diligence performed by banks in connection with our financial restructuring in 2003.

ITEM 16D. ***Exemptions from the Listing Standards for Audit Committees***

Not applicable.

ITEM 16E. ***Purchases of Equity Securities by the Issuer and Affiliated Purchasers***

None.

ITEM 17. ***Financial Statements***

Not applicable.

ITEM 18. ***Financial Statements***

Index to Consolidated Financial Statements

We specifically incorporate by reference in response to this item the auditor's report, the consolidated financial statements and the notes to the consolidated financial statements appearing on pages F-2 through F-63.

ITEM 19. ***Exhibits***

Exhibit Number	Description
1.1	— Articles of Association, as amended (unofficial English translation)
2.1	— Deposit Agreement, dated as of May 25, 1993, among Petroleum Geo-Services ASA (the "Company"), Citibank, N.A., as depositary (the "Depositary"), and all holders from time to time of American Depositary Receipts issued thereunder (incorporated by reference to Exhibit(a)(1) of Post-Effective Amendment No. 1 to the Company's Registration Statement on Form F-6 (Registration No. 33-61500))
2.2	— First Amendment to Deposit Agreement, dated as of April 24, 1997, among the Company, the Depositary and all holders from time to time of American Depositary Receipts issued thereunder (incorporated by reference to Exhibit(a)(2) of the Company's Registration Statement on Form F-6 (Registration No. 333-10856))
2.3	— Form of American Depositary Receipt (incorporated by reference to filing under Rule 424(b)(3) relating to the Company's Registration Statements on Form F-6 (Registration No. 333-122046))

The Company and its consolidated subsidiaries are party to several debt instruments under which the total amount of securities authorized does not exceed 10% of the total assets of the Company and its subsidiaries on a consolidated basis. Pursuant to paragraph 2(b)(i) of the instructions to the exhibits to Form 20-F, the Company agrees to furnish a copy of such instruments to the SEC upon request.

4.1 — Contract of Employment dated 26 January 2006 between the Company and Svein Rennemo

4.2 — 2004 CEO Bonus Scheme (incorporated by reference to Exhibit 4.3 of the 2003 Form 20-F)

4.3 — Credit Agreement, dated as of December 16, 2005, among the Company, certain of its subsidiaries and the lender parties thereto

8.1 — Subsidiaries (included in Item 4 of the annual report)

11.1 — Code of Conduct (incorporated by reference to Exhibit 11.1 of the 2004 Form 20-F)

12.1 — Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(a) of the Securities Exchange Act of 1934

12.2 — Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(a) of the Securities Exchange Act of 1934

13.1 — Certification of the Chief Executive Officer and the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and Rule 13a-14(b) of the Securities Exchange Act of 1934

15.1 — Audit Committee Charter (incorporated by reference to Exhibit 15.1 of the 2004 Form 20-F)

15.2 — Remuneration Committee Charter (incorporated by reference to Exhibit 15.2 of the 2004 Form 20-F)

15.3 — Consent of Ernst & Young AS

SIGNATURES

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

PETROLEUM GEO-SERVICES ASA

By: /s/ GOTTFRED LANGSETH

Gottfred Langseth
Chief Financial Officer

Date: April 5, 2006

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PETROLEUM GEO-SERVICES ASA:

We have audited the accompanying consolidated balance sheets of Petroleum Geo-Services ASA and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of operations, changes in shareholders' equity (deficit), and cash flows for each of the two years in the period ended December 31, 2005 and the two months ended December 31, 2003 (Successor), and for the ten months ended October 31, 2003 (Predecessor). These financial statements are the responsibility of the Company's Board of Directors and management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Petroleum Geo-Services ASA and subsidiaries as of December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the two years in the period ended December 31, 2005 and the two months ended December 31, 2003 (Successor), and for the ten months ended October 31, 2003 (Predecessor) in conformity with U.S. generally accepted accounting principles.

As discussed in Note 3 to the consolidated financial statements, the Company emerged from bankruptcy and effective November 1, 2003, adopted fresh-start reporting pursuant to American Institute of Certified Public Accountants Statement of Position 90-7, *"Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"*. As a result, the consolidated financial statements of the Successor are presented on a different basis than those of the Predecessor and, therefore, are not comparable.

As discussed in Note 2 of the consolidated financial statements, the Predecessor changed its accounting principles to adopt, as of January 1, 2003, the provisions of Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations."*

/s/ Ernst & Young AS

Oslo, Norway
April 4, 2006

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
ASSETS		
Cash and cash equivalents	$ 121,464	$ 132,942
Restricted cash	14,494	25,477
Shares available for sale and investment in securities	13,222	9,689
Accounts receivable, net	213,621	161,283
Unbilled and other receivables	67,785	40,561
Other current assets	67,737	60,506
Total current assets	498,323	430,458
Property and equipment, net	972,018	1,009,008
Multi-client library, net	146,171	244,689
Oil and natural gas assets, net	639	71,491
Restricted cash	10,014	10,014
Deferred tax assets	20,000	—
Investments in associated companies	5,935	5,720
Other long-lived assets	40,086	44,659
Other intangible assets, net	24,386	36,114
Total assets	$1,717,572	$1,852,153
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt and current portion of long-term debt	$ 24,406	$ 19,790
Current portion of capital lease obligations	20,495	25,583
Accounts payable	74,285	81,910
Accrued expenses	164,327	115,256
Income taxes payable	26,318	11,870
Deferred tax liabilities	1,055	761
Total current liabilities	310,886	255,170
Long-term debt	922,134	1,085,190
Long-term capital lease obligations	13,205	33,156
Deferred tax liabilities	497	35,118
Other long-term liabilities	140,790	219,650
Total liabilities	1,387,512	1,628,284
Minority interest in consolidated subsidiaries	785	962
Shareholders' equity:		
Common stock: 60,000,000 shares authorized, issued and outstanding, par value NOK 10, at December 31, 2005 and 20,000,000 shares authorized, issued and outstanding, par value NOK 30, at December 31, 2004	85,714	85,714
Additional paid-in capital	277,427	277,427
Accumulated deficit	(32,105)	(144,683)
Accumulated other comprehensive (loss) income	(1,761)	4,449
Total shareholders' equity	329,275	222,907
Total liabilities and shareholders' equity	$1,717,572	$1,852,153

The accompanying notes are an integral part of these consolidated financial statements.

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars, except share data)			
Revenues services	$1,159,584	$ 945,334	$ 162,827	$ 849,767
Revenues products	36,742	184,134	9,544	112,097
Total revenues	1,196,326	1,129,468	172,371	961,864
Cost of sales services(a)	678,346	587,912	95,044	454,396
Cost of sales products(a)	22,304	44,838	1,910	33,382
Exploration costs	1,438	16,326	—	—
Depreciation and amortization	259,355	368,362	55,699	301,576
Research and development costs	9,918	3,419	598	2,024
Selling, general and administrative costs(a)	67,420	64,816	7,366	44,326
Impairment of long-lived assets	4,575	—	—	95,011
Net gain on sale of subsidiaries	(156,382)	—	—	—
Other operating (income) expense, net	(26,095)	8,112	1,052	21,324
Total operating expenses	860,879	1,093,785	161,669	952,039
Operating profit	335,447	35,683	10,702	9,825
Other income (expense):				
Income from associated companies	276	668	200	774
Interest expense	(96,356)	(110,811)	(16,870)	(98,957)
Debt redemption and refinancing costs	(107,315)	—	—	—
Other financial items, net	5,918	(10,861)	(4,264)	(1,472)
	137,970	(85,321)	(10,232)	(89,830)
Reorganization items:				
Gain on debt discharge	—	—	—	1,253,851
Fresh-start adoption	—	—	—	(532,268)
Cost of reorganization	—	(3,498)	(3,325)	(52,334)
Income (loss) before income tax expense (benefit) and minority interest	137,970	(88,819)	(13,557)	579,419
Income tax expense (benefit)	21,827	48,019	(3,849)	21,911
Minority interest	4,065	940	110	570
Income (loss) from continuing operations before cumulative effect of change in accounting principles	112,078	(137,778)	(9,818)	556,938
Income (loss) from discontinued operations, net of tax	500	3,048	(135)	(2,282)
Income (loss) before cumulative effect of change in accounting principles	112,578	(134,730)	(9,953)	554,656
Cumulative effect of change in accounting principles, net of tax	—	—	—	2,389
Net income (loss)	$ 112,578	$ (134,730)	$ (9,953)	$ 557,045
Basic and diluted income (loss) from continuing operations per share	$ 1.87	$ (2.30)	$ (0.17)	$ 5.39
Income (loss) from discontinued operations, net of tax	0.01	0.05	—	(0.02)
Cumulative effect of change in accounting principle, net of tax	—	—	—	0.02
Basic and diluted net income (loss) per share	$ 1.88	$ (2.25)	$ (0.17)	$ 5.39
Weighted average basic and diluted shares outstanding	60,000,000	60,000,000	60,000,000	103,345,987

Note:

(a) Excluding depreciation and amortization, which is shown separately.

The accompanying notes are an integral part of these consolidated financial statements.

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Cash flows (used in) provided by operating activities:				
Net income (loss)	$ 112,578	$(134,730)	$ (9,953)	$ 557,045
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization charged to expense	259,355	368,362	55,699	301,576
Exploration costs (dry well expensed)	—	11,438	—	—
Non-cash impairments, loss (gain) on sale of subsidiaries and change in accounting principles, net	(151,807)	—	32	92,622
Non-cash effect of fresh start adoption	—	—	—	534,085
Non-cash effect of restructuring	—	—	—	(1,253,851)
Non-cash write-off of deferred debt costs and issue discounts	363	—	—	13,152
Non-cash other operating (income) expense, net	(26,095)	—	—	—
Premium on debt redemption and cost of refinancing expensed	106,952	—	—	—
Cash effects related to discontinued operations	—	—	157	3,185
Provision for deferred income taxes	10,965	27,263	(5,801)	(1,918)
(Increase) decrease in accounts receivable, net	(52,338)	(33,577)	34,582	6,848
Increase (decrease) in accounts payable	(7,625)	25,592	19,391	(18,587)
Loss on sale of assets	1,893	4,128	—	6,193
Net (increase) decrease in restricted cash	1,342	15,646	3,824	(23,728)
Other items	23,473	(1,750)	(35,761)	(51,674)
Net cash provided by operating activities	279,056	282,372	62,170	164,948
Cash flows (used in) provided by investing activities:				
Investment in multi-client library	(55,667)	(41,140)	(9,461)	(81,142)
Capital expenditures	(90,490)	(148,372)	(15,985)	(42,065)
Capital expenditures on discontinued operations	—	—	—	(118)
Proceeds from sales of subsidiaries, net	155,356	2,035	—	50,115
Other items, net	1,300	4,031	357	3,478
Net cash (used in) provided by investing activities	10,499	(183,446)	(25,089)	(69,732)
Cash flows (used in) provided by financing activities:				
Proceeds from issuance of long-term debt	850,000	—	—	—
Repayment of long-term debt	(1,009,152)	(24,167)	(4,850)	(70,496)
Principal payments under capital leases	(25,700)	(22,930)	(3,025)	(22,352)
Net increase (decrease) in bank facility and short-term debt	712	1,962	—	(48)
Distribution to creditors under the restructuring agreement	—	(22,660)	(17,932)	—
Premium on debt redemption, deferred loan costs and reorganization fees	(116,813)	(3,488)	—	—
Net cash used in financing activities	(300,953)	(71,283)	(25,807)	(92,896)
Effect of exchange rate changes on cash	(80)	74	—	14
Net increase (decrease) in cash and cash equivalents	(11,478)	27,717	11,274	2,334
Cash and cash equivalents at beginning of period	132,942	105,225	93,951	91,617
Cash and cash equivalents at end of period	$ 121,464	$ 132,942	$105,225	$ 93,951

The accompanying notes are an integral part of these consolidated financial statements.
Supplementary cash flow information is included in Note 28.

PETROLEUM GEO-SERVICES ASA AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock Number	Common Stock Par value	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Shareholders' Equity
	(In thousands of dollars, except for share data)					
Predecessor Company:						
Balance at December 31, 2002	103,345,987	71,089	1,225,115	(1,458,097)	(30,361)	(192,254)
Comprehensive income (loss):						
Net income				557,045	—	557,045
Other comprehensive income (loss)				—	(1,650)	(1,650)
Total comprehensive income (loss)				557,045	(1,650)	555,395
Reorganization items	(103,345,987)	(71,089)	(1,225,115)	901,052	32,011	(363,141)
Balance at October 31, 2003	—	$ —	$ —	$ —	$ —	$ —
Successor Company:						
Issuance of common stock	20,000,000	$ 85,714	$ 277,427	$ —	$ —	$ 363,141
Comprehensive income (loss):						
Net loss				(9,953)	—	(9,953)
Other comprehensive income				—	446	446
Total comprehensive income (loss)				(9,953)	446	(9,507)
Balance at December 31, 2003	20,000,000	85,714	277,427	(9,953)	446	353,634
Comprehensive income (loss):						
Net loss				(134,730)	—	(134,730)
Other comprehensive income				—	4,003	4,003
Total comprehensive income (loss)	—	—	—	(134,730)	4,003	(130,727)
Balance at December 31, 2004	20,000,000	85,714	277,427	(144,683)	4,449	222,907
Share split June 8, 2005	40,000,000					
Comprehensive income (loss):						
Net income				112,578	—	112,578
Other comprehensive (loss)				—	(6,210)	(6,210)
Total comprehensive income (loss)	—	—	—	112,578	(6,210)	106,368
Balance at December 31, 2005	60,000,000	$ 85,714	$ 277,427	$ (32,105)	$ (1,761)	$ 329,275

The Company's ability to pay dividends is among other things limited to free equity as defined in Norwegian corporate law and measured on the basis of the unconsolidated financial statements of the parent company, Petroleum Geo-Services ASA, as prepared in accordance with generally accepted accounting principles in Norway. At December 31, 2005, Petroleum Geo-Services ASA had $595,556,580 (equivalent to Norwegian kroner 4,028,291,106) of free equity.

The components of Accumulated Other Comprehensive Income (loss) are as follows:

	Net Foreign Currency Translation Adjustments	Net Unrealized Gain (Loss) Investments	Net Gain (Loss) Cash Flow Hedges	Pension Minimum Liability	Accumulated Other Comprehensive Income (Loss)
	(In thousands of dollars)				
Predecessor Company:					
Balance at December 31, 2002	$(26,347)	$ —	$ —	$(4,014)	$(30,361)
Ten months ended October 31, 2003	1,580	—	—	(3,230)	(1,650)
Reorganization items	24,767	—	—	7,244	32,011
Balance at October 31, 2003	$ —	$ —	$ —	$ —	$ —
Successor Company:					
Two months ended December 31, 2003	$ 446	$ —	$ —	$ —	$ 446
Balance at December 31, 2003	446	—	—	—	446
Year ended December 31, 2004	(1,667)	5,889	—	(219)	4,003
Balance at December 31, 2004	(1,221)	5,889	—	(219)	4,449
Year ended December 31, 2005	(2,534)	(1,837)	(1,628)	(211)	(6,210)
Balance at December 31, 2005	$ (3,755)	$ 4,052	$(1,628)	$ (430)	$ (1,761)

The accompanying notes are an integral part of these consolidated financial statements.

NOTE 1 — General Information about the Company and Basis of Presentation

Petroleum Geo-Services ASA ("PGS ASA") is a public limited liability company established under the laws of the Kingdom of Norway in 1991. Unless stated otherwise, references herein to the "Company" and "PGS" refer to Petroleum Geo-Services ASA and its majority-owned subsidiaries and affiliates, companies in which it has and controls a majority voting interest.

PGS is a technologically focused oilfield service company principally involved in providing geophysical services worldwide and floating production services in the North Sea. Globally, PGS provides a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, the Company owns and operates four harsh environment floating production, storage and offloading vessels ("FPSOs"). The Company's headquarters are at Lysaker, Norway. See further discussion of the Company's services in Note 27.

The Company considers its primary basis of accounting to be US generally accepted accounting principles ("US GAAP"), and has prepared these consolidated financial statements in accordance with those principles. PGS is also required to prepare and publish statutory accounts in Norway using Norwegian generally accepted accounting principles ("Norwegian GAAP"). Norwegian GAAP differs materially from US GAAP.

As more fully described in Note 24, the Company sold its wholly owned oil and natural gas subsidiary Pertra AS in March 2005 and entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS in August 2005. The financial results of operations and cash flows for these subsidiaries are included in the consolidated statements of operations and consolidated cash flows for the periods up to the sales dates. The operations are not presented as discontinued due to continuing involvement through the lease of *Petrojarl Varg*.

The Company sold its software company PGS Tigress (UK) Ltd. in December 2003 and its Atlantis subsidiary in February 2003. The financial position and results of operations and cash flows for these subsidiaries have been presented as discontinued operations as of December 31, 2003 and for the year ended December 31, 2003. Discontinued operations and related cash flows for the years ended December 31, 2005 and 2004 include additional proceeds that were contingent on certain events related to discontinued operations sold in 2002 (Production Services). See Note 24 for additional information of these disposals.

Upon emergence from Chapter 11, the Company, adopted "fresh-start" reporting as required under the provisions of AICPA Statement of Position ("SOP") 90-7, *"Financial Reporting by Entities in Reorganization under the Bankruptcy Code,"* effective November 1, 2003. Adoption of fresh-start reporting results in companies reflecting the fair value of the business emerging from bankruptcy (the "reorganization value") in the post fresh-start financial statements, and is required when the holders of the voting common shares immediately before the filing and confirmation of the reorganization plan received less than 50% of the voting shares of the emerging company and when the company's reorganization value is less than its post-petition liabilities and allowed claims. Since these conditions were met, the Company adopted fresh-start reporting, and as a result, in these consolidated financial statements, the terms "Successor" and "Successor Company" refer to PGS' financial statements subsequent to the emergence from Chapter 11 and the terms "Predecessor" and "Predecessor Company" refer to PGS' financial statements for periods up to the emergence from Chapter 11 including the effect of the reorganization plan. The adoption of fresh-start reporting reflects the Company's reorganization value as its new basis in accounting, new accounting pronouncements it was required to adopt with fresh-start reporting and changes in certain of its accounting policies. The Company's financial information in Successor Company periods should not be compared to financial information from Predecessor Company periods as they are not comparable.

NOTE 2 — Summary of Significant Accounting Policies

Consolidation and Equity Investments.

The Company's consolidated financial statements include all transactions of PGS ASA, its wholly owned and majority owned subsidiaries that it controls and equity investments. Subsidiaries are consolidated in the financial statements from the point in time when the Company gains control. Acquisitions are accounted for using the purchase method of accounting. Acquisition prices are assigned to the assets and liabilities of the subsidiaries using their fair value at the date of acquisition. Any excess of purchase cost over fair value of assets and liabilities is recorded as goodwill. All inter-company transactions and balances have been eliminated in the consolidation. In those cases where the subsidiaries are not wholly owned, the minority interests are separately presented in the consolidated statements of operations and consolidated balance sheets.

Investments in associated companies in which the Company has an ownership interest equal to or greater than 20% but equal to or less than 50% and where the Company has the ability to exercise significant influence are accounted for using the equity method.

The Company periodically reviews its investments in associated companies to determine if a loss in value has occurred that is other-than-temporary. PGS considers all available information, including the recoverability of its investment, the earnings and near-term prospects of the investee company, factors related to the industry, conditions of the investee company and the ability, if any, to influence the management of the investee company.

Shares available for sale and investments in securities with an available market value are carried at fair value at each balance sheet date, with unrealized holding gains and losses reported in "unrealized gain (loss) investments" in other comprehensive income until realized.

Variable Interest Entities.

In January 2003, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 46 ("FIN 46") *"Consolidation of Variable Interest Entities"*, and in December 2003, the FASB issued a revised FIN 46 ("FIN 46R"), which address when a company should include in its financial statements the assets, liabilities and activities of another entity. FIN 46R requires consolidation of a variable interest entity ("VIE") if the reporting entity is subject to a majority of the risk of loss from the VIE's activities or is entitled to receive a majority of the VIE's residual returns or both. The consolidation requirements of FIN 46R apply immediately to VIEs created after January 31, 2003, and to all other existing structures commonly referred to as special purpose entities. The consolidation requirements applied to VIEs that were created prior to January 31, 2003 and apply to the Company upon the adoption of fresh-start reporting.

The Company has concluded that it is the primary beneficiary of two VIEs: DMNG PGS AS and Walter Herwig AS. Accordingly, these entities are consolidated in the Successor's financial statements. Walter Herwig AS had become a 100% owned subsidiary of the Company by December 31, 2003, and merged with PGS Geophysical AS, also a wholly owned subsidiary, in 2005. The operations, assets and liabilities of DMNG PGS AS are not material to the Company's financial statements.

In addition, the Company has considered its UK leases that were entered into before 2003 (see Note 20) in relation to FIN 46R. As part of the evaluation process, the Company has requested further information about the lessor entities, including information related to their other assets and contractual arrangements. However, the Company has no rights under its agreements with the lessor entities to request or receive such information, and the lessor entities (or their owners) have denied the Company access to any such information. Accordingly, the Company has not been able to affirmatively determine if any of the lessor entities are in fact VIEs, and if any are VIEs, who the primary beneficiary would be. Accordingly, none of these entities are consolidated.

Discontinued Operations.

Subsidiaries that are either held for sale or discontinued are reported as discontinued operations. Revenues and expenses are excluded from revenue and expenses of the Company and reported separately as a one line item in the consolidated statement of operations, net of tax. Assets and liabilities are presented as separate line items in the consolidated balance sheets. For further details about subsidiaries that we have sold or operations that we have discontinued, see Note 24.

Use of Estimates.

The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates, assumptions and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent liabilities. In many circumstances, the ultimate outcome related to the estimates, assumptions and judgments may not be known for several years after the preparation of the financial statements. Actual amounts may differ materially from these estimates due to changes in general economic conditions, changes in laws and regulations, changes in future operating plans and the inherent imprecision associated with estimates.

Cash and Cash Equivalents.

The carrying amounts of cash and cash equivalents approximate fair value. Cash and cash equivalents include demand deposits and all highly liquid financial instruments purchased with maturities of three months or less.

Cash and cash equivalents that are restricted from the Company's use are disclosed separately in the consolidated balance sheets and are classified as current or long-term depending on the nature of the restrictions. Such restrictions primarily relate to cash collateral for bid or performance bonds, employee tax withholdings and restricted deposits under contracts. Restricted cash related to bid or performance bonds amounted to $2.3 million at December 31, 2005 and $11.7 million at December 31, 2004.

Foreign Currency Translation.

The Company's reporting currency is the U.S. dollar as it is the functional currency for substantially all of its operations throughout the world.

The financial statements of non-U.S. subsidiaries using their respective local currency as their functional currency are translated using the current exchange rate method. Under the current exchange rate method, assets and liabilities are translated at the rate of exchange in effect at period end; share par value and paid-in capital are translated at historical exchange rates; and revenue and expenses are translated at the average rates of exchange in effect during the period. Translation adjustments, net of tax, are recorded as a separate component of shareholders' equity.

Operating and Capital Leases.

The Company has significant operating lease arrangements in all of its operating segments and also has some capital lease arrangements for land seismic equipment and UK leases for vessels (see "UK Leases" below). Capital leases are lease arrangements in which the substantial financial risk and control, but not ownership, of the assets is transferred from the lessor to the Company.

The Company accounts for capital lease arrangements as if the Company had acquired the assets, and the present value of the future lease payments is accounted for as liabilities. The assets are depreciated over the expected useful lives or the related lease terms, whichever is shorter.

UK Leases.

The Company has entered into vessel lease arrangements in the United Kingdom ("UK leases") relating to five of its Ramform-design seismic vessels, its FPSO vessel *Petrojarl Foinaven* and the topside production equipment for its FPSO vessel *Ramform Banff* (see Note 20). Generally, under the leases, UK financial institutions ("Lessors") acquired the assets from third parties and the Company leased the assets from the Lessors under long-term charters that give the Company the option to purchase the assets for a bargain purchase price at the end of the charter periods. The Lessors claims tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. The Company indemnified the Lessors for the tax consequence resulting from changes in tax laws or interpretation of such laws or adverse rulings by authorities and for variations in actual interest rates from those assumed in the leases.

Due to the nature of the charters, the Company accounts for these leases as capital leases. The Company legally defeased its future charter obligations for the assets by making up-front, lump sum payments to unrelated large institutional banks ("Payment Banks"), which then assumed the Company's liability for making the periodic payments due under the long-term charters (the "Defeased Rental Payments") and termination sum obligations under the agreements. The Company has no rights to the amounts paid to Payment Banks. Due to the assumption of the charter payment obligations by the Payment Banks, the Lessors legally released the Company as the primary obligor under the charters. Accordingly, the Company accounted for the release as a derecognition of the capital lease obligations with respect to these UK leases.

At the date that the Company executed any UK lease, the Company treated the excess of the capitalized asset value over the amount required to legally defease the charter obligations as a deferred gain. The deferred gain related to indemnification for tax contingencies and for changes in future interest rates. The portion of the deferred gain relating to changes in interest rates was amortized over the term of the respective leases up to the date of adoption of fresh start reporting. The portion of the deferred gain relating to tax contingencies was recognized in income in accordance with Emerging Issues Task Force ("EITF") Issue 89-20, *"Accounting for Cross Border Tax Benefit Leases,"* when the Company determined that the likelihood of the indemnifications becoming effective was remote.

The Defeased Rental Payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum (the "Assumed Interest Rates"). If actual interest rates are greater than the Assumed Interest Rates, the Company receives rental rebates. Conversely, if actual interest rates are less than the Assumed Interest Rates, the Company is required to pay rentals in excess of the Defeased Rental Payments (the "Additional Required Rental Payments"). Such payments are made annually or semi-annually and are recorded on a straight-line basis as other financial items, net.

Effective November 1, 2003, the Company adopted fresh-start reporting and recorded a liability equal to the fair value of the future Additional Required Rental Payments. Such fair value was estimated at the net present value of the Additional Required Rental Payments based on forward market rates for Sterling LIBOR and an 8% per annum discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, $24.6 million British pounds (approximately $47.2 million) at December 31, 2004 and 22.0 million British pounds (approximately $38.1 million) at December 31, 2005.

For fresh-start reporting purposes, the Company estimated and recorded the fair value of the specific tax exposure related to the defeased UK leases noted above using a probability-weighted analysis and a range of possible outcomes. The Company recorded a 16.7 million British pounds (approximately $28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. At December 31, 2004, this liability amounted to approximately $32.1 million. The Company releases applicable portions of this liability if and when the UK Inland Revenue accepts the lessors' claims for capital allowances under each lease. In 2005 the Company released 9.4 million British pounds (approximately $17.2 million) of the liability.

The remaining recorded liability as at December 31, 2005 is 7.3 million British pounds (approximately $12.7 million) (see Note 20).

Receivables Credit Risk.

The Company's trade receivables are primarily from multinational integrated oil companies and independent oil and natural gas companies, including companies owned in whole or in part by foreign governments. The Company manages its exposure to credit risk through ongoing credit evaluations of customers and has provided for potential credit losses through an allowance for doubtful accounts. The allowance for doubtful accounts reflects management's best estimate of probable losses inherent in accounts receivable from trade customers and is based on a number of factors consisting mainly of aging of accounts, historical experience, customer concentration, customer creditworthiness and current industry and economic trends. The Company does not believe that exposure to concentrations of credit risk is likely to have a material adverse impact on its financial position or results of operations.

Property and Equipment.

Property and equipment are stated at cost less accumulated depreciation, amortization and impairment charges. Depreciation and amortization are calculated based on cost less estimated salvage values using the straight-line method for all property and equipment, excluding leasehold improvements and capital leases, which are amortized over the asset life or lease term, whichever is shorter.

The estimated useful lives for property and equipment for the Predecessor and Successor are as follows:

	Successor Company Years	Predecessor Company Years
Seismic vessels	20-25	20-30
Seismic and operations computer equipment	3-15	3-10
FPSO vessels and equipment	25-30	20-30
Buildings and related leasehold improvements	1-30	1-30
Fixture, furniture, fittings and office computers	3-5	3-5

Expenditures for major property and equipment that have an economic useful life of at least one year are capitalized as individual assets and depreciated over their useful lives. Maintenance and repairs, including periodic maintenance and class surveys for FPSOs and seismic vessels, are expensed as incurred. The Company capitalizes the applicable portion of interest costs to major capital projects. When property and equipment are retired or otherwise disposed of, the related cost and accumulated depreciation are removed from the accounts, and any resulting gain or loss is included in the results of operations.

Significant spare parts are capitalized with the asset to which they pertain, while other spare parts, consumables and bunkers are classified as other current assets and stated at the lower of cost and market.

Multi-Client Library.

The multi-client library consists of seismic data surveys to be licensed to customers on a nonexclusive basis. Costs directly incurred in acquiring, processing and otherwise completing seismic surveys are capitalized into the multi-client library, including the applicable portion of interest costs. The cost of the multi-client library is reduced by the amounts related to reduction of deferred tax asset valuation allowances established at fresh-start accounting. (For a further description, see "Income Taxes" below and Note 21.) Prior to its adoption of fresh-start reporting, the Company also capitalized certain indirect costs and other associated costs that could be attributed to the projects, including cost of relocating crews (steaming) between surveys and the cost of yard stays. Subsequent to the adoption of fresh-start reporting, the Company no longer capitalizes such indirect costs.

The Company records its investment in multi-client library in a manner consistent with its capital investment and operating decision analysis, which generally results in each component of the multi-client library being recorded and evaluated separately. Projects that are in the same political regime, with similar geological traits and that are marketed collectively are recorded and evaluated as a group by year of completion (currently applies to certain surveys in Brazil and the Gulf of Mexico).

Amortization of the multi-client library is generally recorded in proportion to revenue recognized to date as a percentage of the total expected revenue. In determining the annual amortization rates applied to the multi-client library, management considers expected future sales and market developments and past experience. These expectations include consideration of geographic location, prospects, political risk, exploration license periods and general economic conditions. Management updates, at least annually, the total expected revenue for each survey or group of surveys of the multi-client library. Because of the inherent difficulty in estimating future sales and market developments, it is possible that the amortization rates could deviate significantly from year to year. To the extent that such revenue estimates, or the assumptions used to make those estimates, prove to be higher than actual revenue, the Company's future operations will reflect lower profitability due to increased amortization rates applied to the multi-client library in later years, and the multi-client library may also become subject to minimum amortization and/or impairment. Effective upon adoption of fresh-start reporting, for purposes of streamlining the accounting method of amortization, on an annual basis the Company categorizes its multi-client surveys into three amortization categories with amortization of 90%, 75% or 60% of sales amounts. Classification of a project into a rate category is based on the ratio of its remaining net book value to its remaining sales estimates. Each category therefore includes surveys as to which the remaining book value as a percentage of remaining estimated sales is less than or equal to the amortization rate applicable to that category.

An integral component of amortization of the multi-client library is the minimum amortization policy. Under this policy, the book value of each survey or group of surveys of the multi-client library is reduced to a specified percentage by year-end, based on the age of each survey or group of surveys in relation to their year of completion. This requirement is applied each year-end regardless of future revenue estimates for the multi-client library survey or group of surveys. The specified percentage generates the maximum permitted book value for each multi-client library survey or group of surveys as the product of the percentage multiplied by the original cost of the multi-client library survey or group of surveys at the respective period end. Any additional or "minimum" amortization charges required are then determined through a comparison of the remaining book value to the maximum permitted book value allowed for each survey or group of surveys in the multi-client library.

Effective with adoption of fresh-start reporting, the Company revised the minimum amortization period from eight years for marine surveys and five years for onshore surveys to five years for both marine and onshore projects from the end of the year of completion (the year when the project is completed and processed data is ready and available for use) and three years for derivative processed projects (processing or reprocessing that creates data that can be marketed and sold as an addition to the existing library) from the end of the year of completion. Existing marine surveys were accorded a transition profile based on sales forecasts used to compute their fair value.

The specified percentages used to determine the maximum book value of multi-client library components are summarized as follows:

	Successor Company % of Total Cost		Predecessor Company % of Total Cost		
Calendar Year	**5-Year Profile**	**3-Year Profile**	**Marine Components (Excluding Brazil)**	**Marine Components (Brazil)**	**Land Components**
Year 1	80%	66%	100%	100%	100%
Year 2	60%	33%	70%	92%	60%
Year 3	40%	0%	55%	76%	40%
Year 4	20%		40%	50%	20%
Year 5	0%		30%	43%	0%
Year 6			20%	34%	
Year 7			10%	20%	
Year 8			0%	0%	

In addition, effective January 1, 2004, the Company classifies as amortization expense in its consolidated statements of operations any write-downs of individual multi-client surveys that are based on changes in project specific expectations and that are not individually material. The Company expects this additional, non-sales related, amortization expense to occur regularly because the Company evaluates each individual project at least annually for impairment or when specific indicators exist. The Company classifies as impairment in its consolidated statements of operations write-downs related to fundamental changes in estimates affecting a larger part of the Company's multi-client library that are material. Prior to 2004 the Company classified as impairment expense all write-downs of multi-client library.

Other Intangible Assets.

Other intangible assets relate to direct costs of software product for internal use, patents, royalties and licenses. Substantially all of the Company's intangible assets were recognized as a consequence of the Company's adoption of fresh-start reporting. Such intangible assets include existing contracts, order backlog and the value of various existing technologies used in the Company's operations. Other intangible assets are stated at cost less accumulated amortization and impairment charges. The cost of other intangible assets is reduced by the amounts related to reduction of deferred tax asset valuation allowances established at fresh-start accounting. (For a further description, see "Income Taxes" below and Note 21.) Amortization is calculated on a straight-line basis over the estimated period of benefit, ranging from one to 10 years.

Other Long-Lived Assets.

Other long-lived assets consist of costs related to entering into long-term loan facilities (deferred debt issue costs), long-term receivables and fresh-start favorable contracts. The Company capitalizes debt issue costs relating to long-term debt, and such costs are charged to interest expense using the effective interest method over the period the associated debt is outstanding. Other long-term receivable includes accounts receivable expected to be collected more than twelve months after the balance sheet date including government grants and contractual receivables related to asset removal obligations.

Impairment of Multi-Client Library.

The Company evaluates the recoverability of its multi-client library in accordance with Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144")*, whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. The level of estimated future sales for each survey, as well as industry conditions, are key factors in determining when seismic data should be evaluated for impairment. Impairments are evaluated at least annually and whenever there are specific indicators. In accordance with the standard, the impairment evaluation is based first on a comparison of the undiscounted future cash flows over each survey's remaining estimated useful life with the carrying value of that survey. If the undiscounted cash flows are equal to or greater than the carrying value of the survey, no impairment is recorded. If the undiscounted cash flows are less than the carrying value of the survey, the difference between the carrying value of the survey and the discounted future value of the expected revenue stream is recorded as an impairment charge.

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 historical and recent revenue trends, oil and gas prospects in particular regions, general economic conditions affecting the Company's customer base, expected changes in technology and other factors that are deemed relevant.

Impairment of Long-Lived Assets (excluding Multi-Client Library).

Long-lived assets, which consist primarily of property, plant and equipment and oil and gas assets (or the group of assets, including the asset in question, that represents the lowest level of separately identifiable cash flows), are assessed for possible impairment when indications of impairments exist in accordance with SFAS 144. If the total of the undiscounted future cash flows is less than the carrying amount of the asset or group of assets, the asset is not recoverable and an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the asset or groups of assets. Other long-lived assets (property and equipment and oil and natural gas assets accounted for under the successful efforts method) are also assessed for possible impairment upon the occurrence of a triggering event. Events that can trigger assessments for possible impairments include, but are not limited to (i) significant decreases in the market value of an asset, (ii) significant changes in the extent or manner of use of an asset, (iii) a physical change in the asset, (iv) a reduction of proved oil and natural gas reserves based on field performance and (v) a significant decrease in the price of oil or natural gas.

Steaming and Mobilization.

Subsequent to the adoption of fresh-start reporting, costs incurred while relocating or "steaming" a vessel or crew from one location to another are expensed as incurred. Onsite project costs such as positioning, deploying and retrieval of equipment at the beginning and end of a project are considered mobilization or demobilization costs and are included in the cost of the multi-client survey or exclusive contract with which the costs are associated. Prior to fresh-start, the Predecessor capitalized a proportionate share of cost incurred while relocating or "steaming" a seismic vessel or crew as part of the cost of multi-client surveys.

Derivative Financial Instruments.

The Company accounts for derivative financial instruments in accordance with SFAS No. 133, *"Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133")*. The Company uses derivative financial instruments to reduce risk exposure related to fluctuations in foreign currency rates and interest rates. Derivative instruments are recognized in the consolidated balance sheets at their fair values while realized and unrealized gains and losses attributable to derivative instruments that do not qualify for hedge accounting are recognized and reported within other financial items, net, in the consolidated statements of operations as they arise.

The Company applies either fair value or cash flow hedge accounting when a transaction meets the specified criteria in SFAS 133 to obtain hedge accounting treatment. To qualify for hedge accounting the instrument should be designated as a hedge at inception. At the time a financial instrument is designated as a hedge, the Company documents the relationship between the hedging instrument and the hedged item.

Documentation includes risk management objectives and strategy in undertaking the hedge transaction, together with the methods that will be used to assess the effectiveness of the hedging relationship. Accordingly, the Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging derivatives have been "highly effective" in offsetting changes in the fair value or cash flows of the hedged item. A hedge is normally regarded as "highly effective" if, at inception and throughout its life, it can be expected, and actual results indicate, that changes in the fair value or cash flows of the hedged item are effectively offset by the changes in the fair value or cash flows of the hedging instrument. Actual results must be within a range of 80% to 125%. Hedge accounting will be discontinued when (a) it is determined that a derivative is not, or has ceased to be, highly effective as a hedge, (b) the derivative expires, or is sold, terminated or exercised, (c) when the hedged item matures or is sold or repaid, or (d) a forecast transaction is no longer deemed highly probable.

The Company applies hedge accounting for its interest rate hedging activities. At December 31, 2005, for a portion of its floating rate debt, the Company has entered into interest rate swaps to effectively change the floating interest rates to fixed interest rates. The Company does not apply hedge accounting for its currency hedging activities (see Note 19).

Revenue Recognition.

The Company recognizes revenue when persuasive evidence of a sale arrangement exists, delivery has occurred or services have been rendered, the sales price is fixed or determinable and collection is reasonably assured. The Company defers the unearned component of payments received from customers for which the revenue recognition requirements have not been met. For contracts after July 1, 2003, the provisions of EITF 00-21, *Revenue Arrangement with Multiple Deliverables* apply. As a result, consideration is allocated among the separate units of accounting based on their relative fair values. The Company's revenue recognition policy is described in more detail below.

Revenue Services.

1. *Geophysical Services (Marine, Onshore and Other).*

(a) Sales of Multi-Client Library Data.

Late sales — The Company grants a license to a customer, which entitles the customer to have access to a specifically defined portion of the multi-client data library. The customer's license payment is fixed and determinable and typically is required at the time that the license is granted. The Company recognizes revenue for late sales when the customer executes a valid license agreement and has access to the licensed portion of the multi-client library and collection is reasonably assured.

Volume sales agreements — The Company grants licenses to customers for access to a specified number of blocks of multi-client library within a defined geographical area. These licenses typically enable the customer to select and access the specific blocks over a period of time. Although the license fee is fixed and determinable in all cases, the payment terms of individual volume sales agreements vary, ranging from payment of the entire fee at the commencement of the volume sales agreement, to installment payments over a multi-year period, to payment of the license fee as the specific blocks are selected.

Revenue recognition for volume sales agreements is based on a proportion of the total volume sales agreement revenue, measured as the customer executes a license for specific blocks and has been granted access to the data and collection is reasonably assured.

Pre-funding arrangements — The Company obtains funding from a limited number of customers before a seismic acquisition project commences. In return for the pre-funding, the customer typically gains the ability to direct or influence the project specifications, to access data as it is being acquired and to pay discounted prices.

Pre-funding revenue is recognized as the services are performed on a proportional performance basis. Progress is measured in a manner generally consistent with the physical progress on the project, and revenue is recognized based on the ratio of the project's progress to date to the total project revenues, provided that all other revenue recognition criteria are satisfied.

(b) Proprietary Sales/Contract Sales.

The Company performs seismic services for a specific customer, in which case the seismic data is the exclusive property of that customer. The Company recognizes proprietary/contract revenue as the services are performed and become chargeable to the customer on a proportionate performance basis over the term of each contract. Progress is measured in a manner generally consistent with the physical progress of the project, and revenue is recognized based on the ratio of the project's progress to date to the total project revenues, provided that all other revenue recognition criteria are satisfied.

(c) Other Geophysical Services.

Revenue from other geophysical services is recognized as the services are performed, provided all other recognition criteria are satisfied.

2. Production Services.

Tariff-based revenue from Production services from operation of FPSO vessels is recognized as production occurs, while day-rate revenue is recognized over the passage of time, provided all other recognition criteria are satisfied.

3. Revenue Products (Pertra).

Revenue from production and sale of oil produced under production licenses is recognized as produced barrels are lifted and ownership passes to the customer, provided all other recognition criteria are satisfied.

Deferred costs associated with a revenue contract are limited to the amount of deferred revenue related to the contract.

Reimbursements received for expenses incurred under a contract are characterized as revenue in accordance with EITF 01-14 *"Income Statement Characterization of Reimbursements Received for 'Out-of-Pocket' Expenses Incurred".*

Income Taxes.

Deferred tax assets and liabilities are recognized for the expected future tax consequences of transactions and events. Under this method, deferred tax assets and liabilities are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Deferred tax assets are reduced by a valuation allowance to record the deferred tax assets at an amount expected to be more likely than not recoverable. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. In accordance with Accounting Principles Board Opinion No. 23, *"Accounting for Income Taxes — Special Areas,"* the Company does not recognize any deferred tax liability on unremitted earnings of foreign subsidiaries when remittance is indefinite.

When the Company adopted fresh start reporting, effective November 1, 2003, the Company established valuation allowances for deferred tax assets. As and when such deferred tax assets, for which a valuation allowance is established, are realized or recognized in subsequent periods, the tax benefit is recorded as a ratable reduction of the carrying value of all long-term intangible assets existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. Any recognition of fresh-start deferred tax assets after intangible assets are reduced to zero will be credited to shareholders' equity.

Accounting standards are not specific on the ordering of recording a reversal of the fresh-start valuation allowance as a reduction to intangibles and other adjustments to intangible balances. As a result, the Company had adopted the following accounting policy. At year end, effects of minimum amortization on the multi-client library are recorded prior to impairment and reversal of fresh-start valuation allowance (see Note 21). Impairments that occur prior to year end (the event leading to the impairment occurred prior to December 31, 2005) are recorded before the reversal of fresh-start valuation allowance. The reversal of the fresh-start valuation allowance as a reduction in the multi-client library is recorded prior to completing the annual impairment test to evaluate whether the carrying value of the multi-client library is recoverable.

Asset Retirement Obligations.

The Company implemented FASB Interpretation No. 47 *"Accounting for Conditional Asset Retirement Obligations" ("FIN 47")* as of December 31, 2005. FIN 47 is an interpretation of SFAS 143 *"Accounting for Asset Retirement Obligations"*, which refers to legal obligations to perform asset retirement activities. FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated, even if timing and/or method of settlement is conditional on a future event that may not be within the control of the entity. The implementation of FIN 47 had no quantitative effect on the Company.

In accordance with Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations" ("SFAS 143")*, the Company records the fair value of an asset retirement obligation as a liability in the period when it is incurred (typically when the asset is installed at the production location). When the liability is recorded, the Company capitalizes the cost by increasing the carrying amount of the related properties, plant and equipment. Over time, the liability is increased for the change in its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Also, revisions to a previously recorded asset retirement obligation may result from changes in the assumptions used to estimate the cash flows required to settle the asset retirement obligation. The effect of such changes is recorded as an adjustment to the related asset.

Commitments and Contingencies.

The Company accrues for loss contingencies when it is probable that a loss will result from a contingency and the amount of the loss can be reasonably estimated.

Fresh-Start Reporting.

In connection with the adoption of fresh-start reporting effective November 1, 2003, the Company adopted new accounting policies for certain transactions and activities, as further described in the individual descriptions of these policies below. The most significant of these are:

- The successful efforts method of accounting for oil and natural gas exploration and development activities was adopted.
- The Company made certain changes to cost capitalization and amortization policies for the multi-client library, including an increase in minimum amortization by reducing the maximum amortization period from eight to five years after completion of a survey. Further, expenditures incurred in

connection with yard stay and steaming of vessels are expensed as incurred. Such expenses were previously recognized as part of multi-client project costs.

In addition, the Company revised certain accounting estimates, including a reduction of depreciable lives of Ramform seismic acquisition vessels and FPSOs, other than the *Petrojarl I*, from 30 to 25 years.

Oil and Natural Gas Assets.

This policy applies only to Pertra, which was sold March 1, 2005 (see Note 24).

Following its adoption of fresh-start reporting, the Company uses the successful efforts method of accounting for oil and natural gas properties. Under this method, all costs of acquiring unproved oil and natural gas properties and drilling and equipping exploratory wells are capitalized pending determination of whether the properties have proved reserves. If an exploratory well is determined not to have commercial quantities of reserves, the drilling and equipment costs for the well are expensed and classified as exploration costs at that time. Such expenses aggregated $11.4 million for the year ended December 31, 2004, while there were no such costs for the years ended December 31, 2005 and 2003. All development drilling and equipment costs are capitalized. Capitalized costs of proved properties are amortized on a property-by-property basis using the unit-of-production method whereby the ratio of annual production to beginning of period proved oil and natural gas reserves is applied to the remaining net book value of such properties. Oil and natural gas reserve quantities represent estimates only, and there are numerous uncertainties inherent in the estimation process. Actual future production may be materially different from amounts estimated, and such differences could materially affect future amortization of proved properties. Geological and geophysical costs are expensed as incurred and presented as exploration costs. Such costs aggregated $1.4 million and $4.9 million for the years ended December 31, 2005 and 2004, respectively, while there were no such costs for the year ended December 31, 2003.

Long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting, are assessed for impairment whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows, undiscounted, is less than the carrying amount of the assets. In this circumstance, an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

Unproved properties are periodically assessed for impairment and a loss is recognized at the time of impairment. Unproved oil and natural gas properties that are individually significant are periodically assessed for impairment by comparing their cost to their estimated value on a project-by-project basis. The remaining unproved oil and natural gas properties, if any, are aggregated and an overall impairment allowance is provided based on historical experience.

Prior to its adoption of fresh-start reporting, the Company used the SEC full cost method of accounting for oil and natural gas properties. Under this method, all costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Such costs include lease acquisition, geological, geophysical, drilling, equipment, interest and overhead. Capitalized overhead costs are limited to salaries and benefits for employees directly involved in the acquisition, exploration and development of the properties as well as other costs directly associated with such activities. Costs are accumulated on a country-by-country basis.

Under the full cost method, capitalized costs are amortized using the unit-of-production method on a country-by-country basis. Unevaluated properties are excluded from the amortization base. Costs associated with unevaluated properties are transferred into the amortization base at such time as the wells are completed, the properties are sold, or the costs have been impaired. Future development costs and dismantlement and abandonment costs are included in the amortizable cost base.

In accordance with the SEC guidelines for the full cost method, the cost bases of proved oil and natural gas properties are limited, on a country-by-country basis, to the estimated future net cash flows from proved oil and natural gas reserves using prices and other economic conditions in effect at the end of the reporting period, discounted at 10%, net of related taxes (ceiling test). If the capitalized cost of proved oil and natural gas properties exceeds this limit, the excess is charged to expense as additional depreciation and amortization.

New Accounting Standards.

December 31, 2005, FASB Interpretation (FIN) No. 47 *"Accounting for Conditional Asset Retirement Obligations" ("FIN 47")* became effective. FIN 47 is an interpretation of SFAS 143 *"Accounting for Asset Retirement Obligations"*, which refers to legal obligations to perform asset retirement activities. FIN 47 requires an entity to recognize a liability for the fair value of a conditional asset retirement obligation, if the fair value of the liability can be reasonably estimated, even if timing and/or method of settlement is conditional on a future event that may not be within the control of the entity. The implementation of FIN 47 did not have any impact on the Company's financial position.

In May 2005, the FASB issued SFAS No. 154, *"Accounting Changes and Error Corrections" ("SFAS 154")*, a replacement of Accounting Principles Board ("APB") Opinion No. 20 and FASB Statement No. 3. SFAS 154 requires retrospective application to prior periods' financial statements of a voluntary change in accounting principle unless it is impracticable. APB Opinion No. 20, *"Accounting Changes,"* previously required that most voluntary changes in accounting principle be recognized by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. SFAS 154 will become effective for accounting changes and corrections of errors made after January 1, 2006.

In December 2004, the FASB issued SFAS No. 153, *"Exchanges of Nonmonetary Assets" ("SFAS 153")*, an amendment of APB Opinion No. 29. SFAS 153 is based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. APB Opinion No. 29, *"Accounting for Nonmonetary Transactions" ("APB 29")* provided an exception to its basic measurement principle (fair value) for exchanges of similar productive assets. Under APB 29, an exchange of a productive asset for a similar productive asset was based on the recorded amount of the asset relinquished. SFAS 153 eliminates this exception and replaces it with an exception for exchanges of nonmonetary assets that do not have commercial substance. SFAS 153 became effective for the Company for nonmonetary asset exchanges occurring after July 1, 2005, and did not have any material impact on our consolidated financial statements.

In December 2004, the FASB issued SFAS No. 123-R *"Share-Based Payment" ("FASB 123-R")*, which requires companies to recognize in the income statement the grant-date fair value of stock options and other equity-based compensation issued to employees. The standard becomes effective for the Company as of January 1, 2006. The Company has no outstanding options and is not currently issuing stock options that would cause the adoption of SFAS 123-R to impact the Company's financial position, cash flows or results of operations.

NOTE 3 — 2003 Financial Restructuring and Fresh-Start Reporting

Background of Restructuring.

The Company had approximately $1.1 billion of debt and other contractual obligations maturing during 2003, of which $930 million were bank and senior note obligations of PGS ASA. Based on the Company's existing business plan and forecast at that time, it became clear that the Company was over leveraged and that a comprehensive financial restructuring was crucial to the long-term viability of the Company. As a result, on July 29, 2003, the Company filed a voluntary petition for protection under Chapter 11 of the United States Bankruptcy Code. The filing was based on a financial restructuring plan that was pre-approved by a majority of banks and bondholders and a group of the Company's largest shareholders. The Company emerged from Chapter 11 on November 5, 2003.

The financial restructuring involved only the parent company and did not involve operating subsidiaries, which continued full operations, leaving customers, lessors, vendors, employees and subsidiary creditors unaffected.

Financial Restructuring.

In accordance with the plan of reorganization, $2,140 million of the Company's senior unsecured debt was canceled and the associated creditors received the following:

- $746 million of unsecured 10% Senior Notes, due 2010;
- $250 million of unsecured 8% Senior Notes, due 2006;
- $4.8 million of an eight-year unsecured senior term loan facility (which the Company fully repaid in May 2004);
- 91% of new ordinary shares of PGS as constituted immediately post restructuring, with an immediate reduction of this shareholding to 61% through a rights offering of 30% of the new ordinary shares to the pre-restructuring shareholders for $85 million, or $14.17 per share; and
- $40.6 million of cash, of which $17.9 million was distributed in December 2003 and $22.7 million in May 2004.

In accordance with the plan, the share capital outstanding immediately prior to the effectiveness of the restructuring, consisting of 103,345,987 shares, par value NOK 5, was cancelled and 20,000,000 new ordinary shares, par value NOK 30, were issued. The pre-restructuring shareholders received 4%, or 800,000, of the new ordinary shares (one new share per 129 old shares), and the right to acquire 30%, or 6,000,000, of the new ordinary shares (1,500,000 of which were committed to shareholders underwriting the rights offering and 4,500,000 of which were available to all pre-restructuring shareholders on a basis of one new share per 23 old shares), for $85 million ($14.17 per share) in the rights offering.

Owners of $144 million of trust preferred securities received 5%, or 1,000,000, of the new ordinary shares. The principal amount of the Company's interest bearing debt and capital lease obligations immediately after the restructuring was approximately $1,210 million, a reduction of approximately $1,283 million.

Reorganization Value.

The Company adopted fresh-start reporting upon its emergence from Chapter 11 in accordance with SOP 90-7. Accordingly, all assets and liabilities were adjusted to reflect their reorganization value as of November 1, 2003, which approximates fair value at the date of reorganization. The Company engaged independent financial advisors to assist in the determination of its reorganization value as defined in SOP 90-7. In the disclosure statement dated September 10, 2003 prepared in the bankruptcy proceeding, the Company, together with financial advisors, determined through various analyses a reorganization value as an enterprise value in the range of $1.3 billion to $1.7 billion. On this basis the Company determined that the reorganization value for the Company as defined by SOP 90-7 should be close to the mid-range of $1.5 billion.

These analyses are necessarily based on a variety of estimates and assumptions which, though considered reasonable by management, may not be realized and are inherently subject to significant business, economic and competitive uncertainties and contingencies, many of which are beyond the Company's control. These estimates and assumptions had a significant effect on the determination of the reorganization value. Accordingly, there can be no assurance that the estimates, assumptions and values reflected in the valuations will be realized, and actual results could vary materially.

Fresh-Start Reporting.

The consolidated balance sheets as of December 31, 2005 and 2004 and the consolidated statements of operations and cash flows for the years ended December 31, 2005 and 2004, and the two months ended December 31, 2003 are for the Successor and give effect to adjustments to the carrying value of assets or amounts and classifications of liabilities that were necessary upon adoption of fresh-start reporting as of November 1, 2003. The consolidated statements of operations and cash flows for the ten months ended October 31, 2003 are for the Predecessor and reflect the assets and liabilities of PGS on a historical cost basis including the effect at October 31, 2003 of the fresh-start adjustments. The adoption of fresh-start reporting had a material effect on the consolidated balance sheet as of December 31, 2004 and on the consolidated statements of operations for the year ending December 31, 2004 and the two-month period ending December 31, 2003 and will have a material impact on consolidated statements of operations for subsequent periods. Consequently, the financial information for the Successor and Predecessor companies are not comparable.

In connection with the adoption of fresh-start reporting on November 1, 2003, the Company also adopted new accounting policies for certain transactions and activities related to the multi-client library, steaming and mobilization costs, certain other property and equipment, and oil and natural gas exploration, development and production activities. All new accounting policies under fresh-start reporting are described in Note 2.

The following table summarizes the adjustments required to record the reorganization and the issuance of the various securities in connection with the implementation of the plan of reorganization:

			Recovery								
PGS ASA Plan of Reorganization Recovery Analysis	Predecessor Company	Elimination of Debt and Equity	Surviving Debt	Cash	2010 Note	2006 Note	Term Loan Facility	Common Stock %	Common Stock Value	Total Recovery %	Total Recovery Value
			(In thousands of dollars, except percentages)								
Other liabilities — not affected	$ 338,536	$ —	$ —	$ —	$ —	$ —	$ —		$ —		$ —
Unsecured Debt	2,140,000	(2,140,000)	—	40,592	745,949	250,000	4,810	91.0%	330,458	64%	1,371,809
Trust Preferred Securities (incl. accrued interest)	155,203	(155,203)	—	—	—	—	—	5.0%	18,157	12%	18,157
Capital lease obligations	89,913	—	89,913	—	—	—	—	—	—	100%	89,913
Senior Secured Debt	113,970	—	113,970	—	—	—	—	—	—	100%	113,970
Debt of Subsidiaries — not affected	5,295	—	5,295	—	—	—	—	—	—	100%	5,295
Common Stockholders	71,089	(71,089)	—	—	—	—	—	4.0%	14,526	20%	14,526
Deficit	(429,531)	429,531	—	—	—	—	—	—	—		—
Total	$2,484,475	$(1,936,761)	$209,178	$40,592	$745,949	$250,000	$4,810	100.0%	$363,141	65%	$1,613,670
Adjusted for fair value adjustment of interest rate variation on UK leases											$ 51,642
Adjusted for cash											(148,912)
Reorganization value											$1,516,400

Fresh-start adjustments reflect the allocation of fair value to current and long-lived assets and the present value of liabilities to be paid as calculated with the assistance of independent third party valuation specialists. Current and long-lived assets were valued based on a combination of the cost, income and market approach. Also considered was technical, functional and economic obsolescence.

In applying fresh-start reporting, the Company followed these principles:

- The reorganization value of the Company was allocated to the Company's assets in conformity with the procedures specified by Statement of Financial Accounting Standards No. 141, *"Business*

Combinations." The sum of the amounts assigned to assets and liabilities was within the range of the estimated reorganization value and close to the mid-range of the valuation. Therefore, there was no excess or deficit value to be allocated to goodwill or long-term assets.

- Each liability and contingency existing as of the fresh-start reporting date, other than deferred taxes, has been stated at the present value of the amounts to be paid, determined at appropriate then current interest rates.
- Deferred taxes were recorded in conformity with applicable income tax accounting standards, principally Statement of Financial Accounting Standards No. 109, *"Accounting for Income Taxes".* Deferred tax assets and liabilities have been recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities (see Note 21). Valuation allowances have been provided for deferred tax assets.
- Changes in existing accounting principles that otherwise would have been required in the consolidated financial statements of the emerging entity within the twelve months following the adoption of fresh-start reporting were adopted at the time fresh-start reporting was adopted.
- Resetting the multi-client library, the property and equipment and oil and natural gas assets to fair value and eliminating all of the accumulated depreciation.

NOTE 4 — Net Gain on Sale of Subsidiaries

In March 2005, the Company sold its wholly owned subsidiary Pertra AS to Talisman Energy (UK) Ltd. and recognized a gain of $149.8 million, including $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg.* As part of the transaction, the Company is entitled to receive additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006, the Company received $8.1 million, representing the 2005 portion of the contingent consideration, which amount was accrued in December 2005, resulting in an aggregate net gain on the sale of Pertra AS of $157.9 million. See Note 24 for additional information relating to the disposal of Pertra AS.

In August 2005, the Company entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS to Reservoir Consultants Holding AS ("RCH"), which is controlled by a group of former PGS employees. RCH has the option to sell the shares back to the Company for an amount equal to the sale consideration, which option expires 12 months from the completion date (August 31, 2005). The Company has recorded an estimated loss of $1.5 million for this transaction. See Note 24 for additional information relating to the agreement.

NOTE 5 — Impairment of Long-Lived Assets and Other Operating (Income) Expense, Net

Impairments of long-lived assets consist of the following:

	Successor Company			Predecessor Company
	Years Ended December 31, 2005	Years Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)			
Multi-client library (Note 10) (a)	$ —	$—	$—	$90,053
Production assets and equipment (Note 9)	—	—	—	328
Seismic assets and equipment (Note 9)	4,575	—	—	3,539
Other long-lived assets	—	—	—	1,091
Total	$4,575	$—	$—	$95,011

(a) The multi-client library impairment for the ten months ended October 31, 2003 is comprised of $85.0 million in Marine Geophysical and $5.1 million in Onshore.

During 2005 the Company decided to convert its 4C crew into a streamer operation, resulting in an impairment of $4.6 million. In 2003, the Company's sales estimates for several of its multi-client surveys were revised downward significantly, resulting in impairments of such surveys.

Other operating (income) expense, net consists of the following:

	Successor Company			Predecessor Company
	Years Ended December 31, 2005	Years Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)			
Release of contingent liability re UK lease (Note 20)	$(17,248)	$ —	$ —	$ —
Gain on claim re equipment	(8,847)	—	—	—
Cost of employees termination and reorganization	—	665	$ 582	19,235
Cost relating to completion of 2002 U.S. GAAP accounts and re-audit of 2001	—	7,447	470	2,089
Total	$(26,095)	$8,112	$1,052	$21,324

NOTE 6 — Shares Available for Sale and Investments in Securities

Shares available for sale relates to the Company's investment in Endeavour International Corp., which investment was originally acquired as consideration for the contribution of licenses to use the Company's seismic data in the North Sea. The Company owns approximately 3.3% of Endeavour's shares, which had an original cost of $3.8 million. In adjusting the shares to fair value, an unrealized loss of $2.1 million has been recorded directly to other comprehensive income for the year ended December 31, 2005. For the year ended December 31, 2004, the Company recorded an unrealized gain of $5.9 million. Fair value of the shares was $7.6 million and $9.7 million as of December 31, 2005 and 2004, respectively.

The Company also has investments in securities with fair value totalling $5.6 million as of December 31, 2005 and recorded an unrealized gain of $0.2 million for the year ended December 31, 2005 directly to other comprehensive income.

NOTE 7 — Accounts Receivable, Net

Accounts receivable, net, consists of the following:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Accounts receivable — trade	$216,157	$162,775
Allowance for doubtful accounts	(2,536)	(1,492)
Total	$213,621	$161,283

The change in allowance for doubtful accounts is as follows:

	Successor Company			Predecessor Company
	December 31, 2005	December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)			
Beginning balance	$ 1,492	$ 3,444	$2,913	$ 4,648
New and additional allowances	2,067	1,001	837	2,615
Write-offs and reversals	(1,023)	(2,953)	(179)	(4,350)
Disposal of subsidiary	—	—	(127)	—
Ending balance	$ 2,536	$ 1,492	$3,444	$ 2,913
Related to:				
Accounts receivable, net	$ 2,536	$ 1,492	$3,115	$ 2,472
Unbilled and other receivables	—	—	329	314
Assets of discontinued operations	—	—	—	127
Total	$ 2,536	$ 1,492	$3,444	$ 2,913

NOTE 8 — Other Current Assets

Other current assets consist of the following:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Prepaid operating expenses	$20,965	$13,053
Spare parts, consumables and supplies	17,485	12,840
Withholding taxes and taxes receivable	13,588	15,821
Prepaid reinsurances	6,572	5,831
Assets of business transferred under a contractual arrangement (Notes 4 and 24)	3,504	—
Produced oil, not lifted	—	5,037
Other	5,623	7,924
Total	$67,737	$60,506

NOTE 9 — Property and Equipment, Net

The components of property and equipment, including property and equipment under capitalized leases, are summarized as follows:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Seismic vessels and equipment	$ 507,607	$ 435,622
Production vessels and equipment	675,062	680,737
Fixtures, furniture and fittings	27,378	18,383
Buildings and other	7,521	4,412
	1,217,568	1,139,154
Accumulated depreciation and impairment	(245,550)	(130,146)
Total	$ 972,018	$1,009,008

The net book value of property and equipment under UK leases were $588.8 million and $616.5 million at December 31, 2005 and 2004, respectively (see Note 20).

As seismic vessels and equipment are not separate cash-generating units, such assets are presented on a combined basis. Vessels and equipment subject to capital leases that are part of a group are presented and evaluated on a combined basis. See Note 2 for a further description of the accounting policy for impairments of long-lived assets.

During 2005 the Company decided to convert its 4C crew into a streamer operation, resulting in an impairment of $4.6 million. Impairment charges were also recorded in the ten months ended October 31, 2003 (see Note 5).

The following table summarizes depreciation expense:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Depreciation expense, net of amounts capitalized into multi-client library	$106,707	$106,629	$18,206	$121,485
Depreciation expense capitalized into multi-client library	5,415	3,982	1,329	11,766

Subsequent Events.

In January 2006 the Company entered into an agreement to purchase the shuttle tanker MT *Rita Knutsen* for $35 million from Knutsen OAS Shipping AS. The transaction was completed on March 9, 2006. The Company considers the vessel to be a possible FPSO solution for several upcoming projects, and the Company intends to begin a conversion when a firm contract for the ship is secured. The vessel will be operated by Knutsen OAS Shipping AS under a bareboat charter agreement until a decision to start conversion is made.

In March 2006, the Company announced that it intends to build a new third generation Ramform seismic vessel at Aker Yards, Langsten, Norway. The Company expects the new Ramform class seismic vessel to cost approximately $85 million from the yard including installation, but excluding the cost of seismic equipment. The new Ramform is expected to be delivered in the first quarter of 2008.

NOTE 10 — Multi-Client Library, Net

The net carrying value of the multi-client library, by the year in which the components were completed, is summarized as follows:

	December 31,	
	2005	2004
	(In thousands of dollars)	
Completed surveys:		
Completed during 1999, and prior years	$ 6,251	$ 26,772
Completed during 2000	5,881	21,976
Completed during 2001	66,626	106,876
Completed during 2002	18,785	35,393
Completed during 2003	14,859	33,296
Completed during 2004	4,347	11,620
Completed during 2005	7,746	—
Completed surveys	124,495	235,933
Surveys in progress	21,676	8,756
Multi-client library	$146,171	$244,689

The following table summarizes multi-client library impairment charges, amortization expense, capitalization of interest and depreciation and amounts credited to the multi-client library related to reduction of deferred tax asset valuation allowances established at fresh-start accounting:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Impairment charges (Note 5)	$ —	$ —	$ —	$ 90,053
Amortization expense	134,469	208,468	33,347	148,399
Interest capitalized into multi-client library	1,878	1,461	375	2,083
Depreciation capitalized into multi-client library	5,415	3,982	1,329	11,766
Reduction of deferred tax asset valuation allowance (Note 21)	25,312	—	—	—

Amortization expense for the year ended December 31, 2005 includes $35.4 million of additional non-sales related amortization. This amount includes $20.4 million in minimum amortization and $15.0 million of non-sales related amortization (impairment) to reflect reduced fair value of future sales on certain individual surveys ($14.4 million in Marine Geophysical and $0.6 million in Onshore). For the year ended December 31, 2004 the additional non-sales related amortization totaled $48.8 million of which $28.9 million was for minimum amortization and $19.9 million for non-sales related amortization (impairment) ($18.8 million in Marine Geophysical and $1.1 million in Onshore). For the two months ended December 31, 2003 and the ten months ended October 31, 2003, the Company recognized $0.0 million and $36.6 million, respectively, in minimum amortization.

For informational purposes, the following shows the hypothetical application of the Company's minimum amortization requirements to the components of the existing multi-client library. These minimum amortization requirements are calculated as if there will be no future sales of these components or any additional effect of reduction in deferred tax asset valuation allowances credited to the multi-client library.

	Minimum Future Amortizations
	(In thousands of dollars)
During 2006	$ 33,680
During 2007	43,816
During 2008	43,975
During 2009	9,779
During 2010	7,814
During 2011	7,107
Future minimum amortization	$146,171

Because the minimum amortization requirements generally apply to the multi-client library on a survey-by-survey basis rather than in the aggregate, the Company may incur significant minimum amortization charges in a given year even if the aggregate amount of ordinary amortization charges recognized exceeds the aggregate minimum amortization charges above.

At the Company's adoption of fresh-start reporting, effective November 1, 2003, the Company established valuation allowances for deferred tax assets. If such deferred tax assets, for which a valuation allowance is established, are realized or recognized in subsequent periods, the reversal of valuation allowance will be recorded as a ratable reduction of the carrying value of all long-term intangible assets and certain favorable lease contracts existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. At December 31, 2005, the Company recorded a $25.3 million reduction of the carrying amounts of the multi-client library due to such a reversal of valuation allowance, which is reflected in the table above as a reduction in gross costs (see Note 21).

NOTE 11 — Other Intangible Assets, Net

The components of other intangible assets, net, are summarized as follows:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Existing technology	$ 29,329	$ 30,548
Existing contracts	16,643	16,772
Order backlog	5,401	5,401
Patents, royalties and licenses	1,687	659
Total cost	53,060	53,380
Accumulated amortization	(28,674)	(17,266)
Total	$ 24,386	$ 36,114

Other intangible assets existing at December 31, 2005 and 2004 were primarily recognized in conjunction with the adoption of fresh-start reporting, effective November 1, 2003. The following table summarizes amortization expense amounts credited to the other intangible assets related to reduction of deferred tax asset valuation allowances established at fresh-start accounting:

	Successor Company			Predecessor Company
	Years Ended December 31, 2005	Years Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)			
Amortization expense	$11,458	$13,778	$3,488	$1,480
Reduction of deferred tax asset valuation allowance (Note 21)	1,348	3,291	—	—

The weighted average remaining amortization period for other intangible assets as of December 31, 2005 is 6.3 years, and the amortization expense related to these assets under existing amortization plans is $5.9 million (2006), $4.1 million (2007), $3.7 million (2008), $2.2 million (2009) and $8.5 million (2010 and thereafter). These amortizations are calculated as if there will be no additional effect of reduction in deferred tax asset valuation allowances credited to the other intangible assets.

As described in Note 10, the reduction of the valuation allowance for deferred tax assets established in fresh-start accounting results in a reduction of certain intangible assets. At December 31, 2005 and 2004, the Company recorded $1.3 million and $3.3 million, respectively, in reduction of the carrying amounts of other intangible assets due to reversal of valuation allowance (see Note 21).

NOTE 12 — Other Long-Lived Assets

Other long-lived assets consist of the following:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Long-term receivables	$16,893	$14,945
Governmental grants and contractual receivables	5,577	17,204
Favorable lease contracts	7,829	10,444
Deferred debt issue costs	9,787	2,066
Total	$40,086	$44,659

Governmental grants and contractual receivables relate to grants from the Norwegian Government and contractual payments from FPSO contract counterparties that the Company is entitled to receive to cover parts of its asset retirement obligations (see Notes 2 and 14).

The fair value of certain favorable lease contracts totaling $14.2 million were recognized in the Company's balance sheet in connection with the adoption of fresh-start reporting, effective November 1, 2003. The amortization of these contracts over the remaining lease periods (which average approximately 4 years) is recorded as an increase of lease expense as part of cost of sales. The Company recorded $2.1 million, $2.4 million and $0.4 million of such increase in lease expense for the years ended December 31, 2005 and 2004 and the two months ended December 31, 2003, respectively.

As described in Note 10, the reduction of the valuation allowance for deferred tax assets established in fresh-start accounting results in a reduction of certain intangible assets. At December 31, 2005 and 2004, the Company recorded $0.5 million and $1.0 million, respectively, in reduction of the carrying amounts of favorable lease contracts due to reversal of valuation allowance (see Note 21).

NOTE 13 — Accrued Expenses

Accrued expenses consist of the following:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Accrued employee payroll	$ 44,864	$ 37,659
Accrued vessel operating expenses	30,074	17,080
Customer advances and deferred revenue	29,723	12,070
Forward exchange contracts (Note 19)	7,234	—
Received, not invoiced, property and equipment	7,967	5,618
Accrued commissions	7,550	9,683
Accrued interest expenses	5,778	3,394
Liabilities of business transferred under a contractual arrangement (Notes 4 and 24)	3,504	—
Accrued severance	27	290
Other	27,606	29,462
Total	$164,327	$115,256

Changes in accrued severance and restructuring costs are as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Beginning balance	$ 290	$ 5,061	$ 8,367	$ 1,215
Additional and adjustment of allowances	(40)	(632)	1,764	18,469
Severance and restructuring costs paid	(223)	(4,139)	(5,070)	(11,317)
Ending balance	$ 27	$ 290	$ 5,061	$ 8,367

NOTE 14 — Other Long-Term Liabilities

Other long-term liabilities consist of the following:

	December 31,	
	2005	2004
	(In thousands of dollars)	
Accrued liabilities UK leases (Note 20)	$ 50,765	$ 79,344
Pension liability (Note 22)	45,443	52,472
Asset retirement obligations (“ARO”) (Note 2)	20,015	58,518
Tax contingencies	19,184	25,522
Interest rate swaps (Note 19)	1,628	—
Other	3,755	3,794
Total	$140,790	$219,650

The following table presents changes in asset retirement obligations for the years ending December 31, 2005 and 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003:

	Successor Company			Predecessor Company
	December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Balance at beginning of period	$ 58,518	$50,016	$49,847	$ 59,767
Accretion expense	1,426	4,005	599	3,793
Liabilities settled in the period	(15)	—	(430)	—
Disposal of subsidiary (Pertra AS)	(39,914)	—	—	—
Revision in estimated cash flow/fair value	—	4,497	—	(13,713)
Balance at end of period	$ 20,015	$58,518	$50,016	$ 49,847

The ARO liability as of December 31, 2005 relates mainly to the Banff field and will be settled at the end of the contract, currently expected to be no later than 2014.

As of December 31, 2005, the Company had asset retirement obligations for the sub-sea production facility associated with *Ramform Banff* FPSO operating in the North Sea. These obligations generally relate to restoration of the environment surrounding the facility and removal and disposal of all the production equipment. The asset retirement obligation will be covered in part by contractual payments from FPSO contract counterparties (see Note 12). The receivable has been included in the consolidated balance sheets under other long-lived assets.

NOTE 15 — Short-Term Debt and Current Portion of Long-Term Debt

Short-term debt and current portion of long-term debt consist of the following:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Short-term debt (see Note 16)	$ 2,674	$ 1,962
Current portion of long-term debt (see Note 16)	21,732	17,828
Total	$24,406	$19,790

NOTE 16 — Debt

Long-Term Debt.

Long-term debt consists of the following:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Unsecured:		
10% Senior Notes, due 2010	$ 4,624	$ 745,949
8% Senior Notes, due 2006	—	250,000
Secured:		
Term loan, due 2012, Libor + margin (see below)	850,000	—
8.28% First Preferred Mortgage Notes, due 2011	87,930	98,920
Other loans, due 2006	1,312	8,149
Total debt	943,866	1,103,018
Less current portion	(21,732)	(17,828)
Total long-term debt	$922,134	$1,085,190

Aggregate maturities of long-term debt as of December 31, 2005 are as follows:

	December 31, 2005
	(In thousands of dollars)
Year of repayment:	
2006	$ 21,732
2007	21,400
2008	22,540
2009	23,660
2010	29,554
Thereafter	824,980
Total	$ 943,866

In December 2005, the Company entered into a new credit agreement, establishing a term loan of \$850 million ("Term Loan") and a revolving credit facility ("RCF") of \$150 million (see below). The Term Loan amortizes 1% per annum, with the remaining balance due in 2012, and bears interest at a rate of LIBOR plus a margin that depends on our leverage ratio. Leverage ratio, as defined in the Credit Agreement, is the ratio of consolidated Indebtedness to Consolidated EBITDA reduced by multi-client investments made for the period in question. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.5% per annum. Below that level, the margin will be 2.25% per annum. The credit agreement generally requires the Company to apply 50% of excess cash flow to repay outstanding borrowings for periods when our leverage ratio exceeds 2:1. Excess cash flow for any period is defined as net cash flow provided by operating activities during that period less capital expenditures made in that period or committed to be made in the next period, less debt service payments and less accrued income taxes to be paid in the next period. The Company can make optional payments to reduce the principal at no penalty. The Term Loan is an obligation of PGS ASA and PGS Finance Inc. as co-borrowers, is secured by pledges of shares of certain material subsidiaries and is guaranteed by certain material subsidiaries.

The Company has hedged the interest rate on 50% of the borrowings under the Term Loan by entering into interest rate swaps where the Company receives floating interest rate based on 3 months LIBOR and pays fixed interest rate payments based on LIBOR for 3 and 5 year maturities. See Note 19 for further information.

The 10% Senior Notes due 2010 ("10% Notes") bear interest at 10% per annum payable semi-annually and mature in November 2010 with no required principal payments until maturity. The 10% Notes are callable by the Company beginning in November 2007 and are callable thereafter at par plus a premium of 5% declining linearly until maturity. In December 2005, the Company refinanced and retired \$741.3 million of the 10% Notes. The 10% Notes are unsecured obligations of PGS ASA.

The 8.28% First Preferred Mortgage Notes due 2011 ("8.28% Notes") bear interest at 8.28% per annum, and interest and scheduled principal amounts are payable semi-annually. The 8.28% Notes are subject to redemption at par on a pro rata basis through operation of a mandatory sinking fund on a semi-annual basis according to a schedule and are subject to optional redemption by the Company beginning in June 2006 at a redemption price equal to 100% of the principal amount plus a make whole premium that is based on U.S. treasury rates plus 0.375%. The 8.28% Notes are secured by, among other things, a mortgage on the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. In addition, there is established under the indenture for the 8.28% Notes a debt service reserve fund, which was initially funded in an amount (approximately \$10 million) equal to the maximum interest and sinking fund payment due on the 8.28% Notes on any payment date for such notes through December 1, 2010. Such additional amount has been invested in a funding agreement that serves as a source of funds that, together with charter hire payments made by a Company subsidiary under charters for the *Ramform Explorer* and the *Ramform Challenger* vessels, are used to make debt service payments on the 8.28% Notes. This debt service reserve fund investment is presented as long-term restricted cash in the consolidated balance sheets because funds derived from the investment will be used to make final debt service payments on the 8.28% Notes.

Bank Credit Facilities.

In December 2005, the Company replaced its secured \$110 million revolving credit facility, originally maturing in 2006, with a new revolving credit facility ("RCF") of \$150 million. The new RCF is part of the same credit agreement as the \$850 million Term Loan described above and matures in 2010. The Company may use up to \$60 million of capacity under the RCF for letters of credit and may borrow U.S. dollars, or any other currency freely available in the London banking market to which the lenders have given prior consent, under the RCF for working capital and for general corporate purposes. The Company may use these letters of credit, which can be obtained in various currencies, to secure, among other things, performance and bid bonds required in our ongoing business. Borrowings under the RCF bear interest at a rate equal to LIBOR plus a margin that depends on our leverage ratio. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.25%; at a leverage ratio between 2:1 and 2.25:1, the applicable margin will be 2.00%; and at a leverage ratio below 2:1, the applicable margin will be 1.75. At December 31, 2005, $14.6 million of letters of credit were issued under the RCF and the applicable margin was 2.25% per annum. In addition, the Company may be able to borrow an additional $250 million that would be secured by the same collateral that secures the Term Loan and borrowings under the RCF.

Short-Term Debt.

Net short-term debt was $2.7 million as of December 31, 2005, relating to our Onshore business. As of December 31, 2004, net short-term debt was $2.0 million, of which $1.8 million related to the purchase of the seismic vessel *Falcon Explorer.*

Covenants.

Our December 2005 credit facility contains financial covenants and negative covenants that restrict us in various ways. The facility provides that

- our total leverage ratio may not exceed 3.50 to 1.0 in 2006, 3.25 to 1.0 in 2007 and 3.00 to 1.0 in 2008, and may not exceed 3.00 to 1.0 at the time of our proposed separation transaction described under "Information on the Company — Proposed Separation of the Geophysical and Production Businesses" in Item 4 of this annual report,
- our consolidated interest coverage ratio (defined as the ratio of consolidated EBITDA less multi-client investments to consolidated interest expense) must be at least 3.0 to 1.0, and
- our consolidated fixed charge coverage ratio (defined as the ratio of consolidated EBITDA less multi-client investments to consolidated fixed charges) must be at least 1.3 to 1.0.

In addition, the credit agreement restricts our ability, among other things, to sell assets; incur additional indebtedness or issue preferred stock; prepay interest and principal on our other indebtedness; pay dividends and distributions or repurchase our capital stock; create liens on assets; make investments, loans, guarantees or advances; make acquisitions; engage in mergers or consolidations; enter into sale and leaseback transactions; engage in transactions with affiliates; amend material agreements governing our indebtedness; change our business; enter into agreements that restrict dividends from subsidiaries; and enter into speculative financial derivative agreements.

The Company is in compliance with the covenants in its loan and lease agreements as of December 31, 2005.

Pledged Assets.

Certain seismic vessels and seismic equipment with a net book value of $45.4 million and $55.2 million at December 31, 2005 and 2004, respectively, are pledged as security under the Company's short-term and long-term debt. In addition, under the credit agreement established in December 2005, certain shares in material subsidiaries have been pledged as security.

Letter of Credit and Guarantees.

The Company had aggregate outstanding letters of credit and related types of guarantees, not reflected in the accompanying consolidated financial statements, of $32.7 million (including $14.6 million described above) and $30.1 million at December 31, 2005 and 2004, respectively.

NOTE 17 — Interest Expense

Interest expense consists of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Interest expense, gross	$(98,234)	$(112,272)	$(17,245)	$(92,504)
Interest on trust preferred securities	—	—	—	(8,536)
Interest capitalized in multi-client library (Note 10)	1,878	1,461	375	2,083
Total interest expense	$(96,356)	$(110,811)	$(16,870)	$(98,957)

NOTE 18 — Other Financial Items, Net

Other financial items, net, consist of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Interest income	$ 7,442	$ 4,840	$ 1,050	$ 4,467
Foreign currency gain (loss)	4,098	(8,024)	(5,208)	(4,286)
Sale of shares in Aqua Exploration Ltd.	—	1,500	—	—
Other	(5,622)	(9,177)	(106)	(1,653)
Total other financial items, net	$ 5,918	$(10,861)	$(4,264)	$(1,472)

Other includes additional required rental payments relating to UK leases of $7.2 million for each of the years ended December 31, 2005 and 2004, $4.9 million for the two months ended December 31, 2003 and $1.5 million for the ten months ended October 31, 2003 (see Note 20).

NOTE 19 — Financial Instruments

Fair Values of Financial Instruments.

The carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, unbilled and other receivables, other current assets, accounts payable and accrued expenses approximate their respective fair values because of the short maturities of those instruments. The carrying amounts and the estimated fair values of debt instruments are summarized as follows:

	December 31, 2005			December 31, 2004		
	Carrying Amounts	Notional Amounts	Fair Values	Carrying Amounts	Notional Amounts	Fair Values
	(In thousands of dollars)					
Long-term debt (Note 16)	$943,866	$ —	$947,105	$1,103,018	$ —	$1,218,386
Derivatives:						
Forward exchange contracts (Note 13)	(7,234)	193,536	(7,234)	—	—	—
Interest rate swaps (cash flow hedging instruments) (Note 14)	(1,628)	425,000	(1,628)	—	—	—
Commodity derivatives	—	—	—	(2,583)	—	(2,583)

The fair values of the long-term debt instruments, forward exchange contracts and interest rate swaps are estimated using quotes obtained from dealers in such financial instruments or latest quoted prices at Bloomberg.

There is established under the indenture for the 8.28% Notes a debt service reserve fund, which was initially funded in an amount (approximately $10 million) equal to the maximum interest and sinking fund payment due on the 8.28% Notes on any payment date for such notes through December 1, 2010. Such additional amount has been invested in a funding agreement that serves as a source of funds that, together with charter hire payments made by a Company subsidiary under charters for the *Ramform Explorer* and the *Ramform Challenger* vessels, are used to make debt service payments on the 8.28% Notes. The amounts held in or payable into the debt service reserve fund will be used as part of the final payments on the 8.28% Notes. The Company classifies this amount as restricted cash (long-term) in its consolidated balance sheets ($10 million).

Interest Rate Exposure.

The Company holds interest rate derivative instruments. As of December 31, 2005, the Company had outstanding interest rate swap agreements in the aggregate notional amount of $433.6 million, of which $8.6 million either matured in January 2006 or were terminated in February 2006. As of December 31, 2005, we had entered into interest rate swaps relating to $425 million of the $850 million Term Loan and changed our interest rate exposure from floating to fixed interest rates for the $425 million notional amount. We account for these swaps as interest rate hedges. Under these interest rate swap agreements, the Company receives floating interest rate payments based on 3 month LIBOR and pays fixed interest rate payments. As to a notional amount of $150 million, a fixed rate of 4.84% will apply through December 2008. As to a notional amount of $275 million, an average fixed rate of 4.88% will apply through December 2010. The aggregate negative fair value of these interest rate swap agreements at December 31, 2005 was approximately $1.6 million and is reported as other long-term liabilities. The same amount, in accordance with SFAS 133, is recorded as a reduction in other comprehensive income as the effective portion of the designated and qualifying hedging instrument (the interest swaps).

Foreign Exchange Exposure.

The Company is exposed to currency fluctuation due to a predominantly USD-based revenue stream, while the Company's expenses are incurred in various currencies. The larger expense currencies other than the

USD are GBP and NOK. In 2005, the Company adopted a foreign currency hedging program by buying NOK and GBP on forward contracts. As of December 31, 2005, the Company had open forward contracts to buy GBP and NOK amounting to approximately $193.5 million with a negative fair value of $7.2 million reported as accrued expenses. As of December 31, 2004, the Company did not have any open forward exchange contracts. The currency forward contracts are not accounted for as hedges.

Commodity Derivatives.

Through February 2005, the Company operated in the worldwide crude oil market through its subsidiary Pertra AS, which was sold March 1, 2005 (see note 24). By reason of its ownership of Pertra, the Company had exposure to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2004 (combined) was 5,317,134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2005 and 2004, the Company did not have any outstanding derivative commodity instruments. In the first half of 2004, we sold forward 950,000 barrels of our 2004 second half production at an estimated average of $30.50 per barrel. Of the total amount sold forward, 250,000 barrels sold forward at an average price of $29.91 per barrel were not delivered at December 31, 2004, but were delivered in early January 2005. Estimated fair value of the contract at December 31, 2004 was a net liability of $2.6 million, which is included in accrued expenses in the consolidated balance sheets and in revenues products in the consolidated statements of operations, based on mark-to-market rates.

NOTE 20 — Commitments and Contingencies

Leases.

The Company has operating lease commitments expiring at various dates through 2015. The Company also has capital lease commitments, primarily for onshore-based seismic equipment, expiring at various dates through 2008. At December 31, 2005, future minimum payments related to non-cancelable operating and capital leases with lease terms in excess of one year are as follows:

	December 31, 2005	
	Operating Leases	Capital Leases
	(In thousands of dollars)	
2006	$ 39,194	$ 23,094
2007	27,318	7,308
2008	26,889	6,869
2009	24,613	—
2010	12,597	—
Thereafter	27,852	—
Total	$158,463	37,271
Imputed interest		(3,571)
Net present value of capital lease obligations		33,700
Current portion of capital lease obligations		(20,495)
Long-term portion of capital lease obligations		$ 13,205

The Company entered into a capital lease arrangement of $0.7 million for the year ended December 31, 2005, while there were no such new arrangements for the year ended December 31, 2004.

Future minimum payments related to non-cancelable operating leases reflect $8.2 million in sublease income for 2006, related to a time-charter of one FPSO shuttle tanker to a third party.

The future minimum payments under the Company's operating leases relate to the Company's operations as follows:

	December 31, 2005
	(In thousands of dollars)
Marine seismic and support vessels	$ 6,267
Onshore seismic equipment	75
FPSO shuttle and storage tankers	56,821
Buildings	94,341
Fixtures, furniture and fittings	959
Total	$158,463

Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above is charter hire for the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. The Company is required to charter the vessel for as long as *Ramform Banff* produces the Banff field, which could extend to 2014 depending on the customer/field operator. The maximum payment for the charter through 2014 is $97.8 million, of which only charter hire for the six month period ending June 30, 2006 is included in the table above.

Rental expense for operating leases, including leases with terms of less than one year, was $59.6 million and $59.4 million for the years ended December 31, 2005 and 2004, $12.2 million for the two months ended December 31, 2003 and $76.3 million for the ten months ended October 31, 2003. Rental expense for operating leases are net of sub-lease income related to time charter of FPSO shuttle tankers to a third party amounting to $10.0 million and $10.3 million for the years ended December 31, 2005 and 2004, $1.4 million for the two months ended December 31, 2003 and $16.6 million for the ten months ended October 31, 2003.

Other.

The Company has contingencies resulting from litigation, other claims and commitments incidental to the ordinary course of business. Management believes that the probable resolution of such contingencies will not materially affect the financial position, results of operations or cash flows of the Company.

UK Leases.

The Company entered into capital leases from 1996 to 1998 relating to *Ramforms Challenger, Valiant, Viking, Victory* and *Vanguard;* the FPSO *Petrojarl Foinaven;* and the production equipment for the *Ramform Banff*. The terms for these leases ranged from 13-25 years. The Company has indemnified the lessors for the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities and for variations in actual interest rates from those assumed in the leases. There are no limits on either of these indemnities. Reference is also made to the description in Note 2 — UK Leases.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Although the UK Inland Revenue generally deferred for a period of time agreeing to the capital allowances claimed under such leases pending the outcome of a legal proceeding in which the Inland Revenue was challenging capital allowances associated with a defeased lease, in November 2004, the highest UK court of appeal ruled in favor of the taxpayer and rejected the position of the Inland Revenue. In connection with the adoption of fresh-start reporting on November 1, 2003 and before the

November 2004 ruling, the Company recorded a liability of 16.7 million British pounds (approximately $28.3 million). The Company releases applicable portions of this liability if and when the Inland Revenue accepts the lessors' claims for capital allowances under each lease. In 2005 the Company released 9.4 million British pounds (approximately $17.2 million) of the liability, recorded as other operating (income) expense, net (see Note 5).

The remaining accrued liability at December 31, 2005 of 7.3 million British pounds (approximately $12.7 million) relates to the *Petrojarl Foinaven* lease, where the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available. If the Inland Revenue were successful in challenging that rate, the lessor would be liable for increased taxes on *Petrojarl Foinaven* in early periods (and decreased taxes in later years), and the Company's rental would increase. How much the rentals could increase depends primarily on how much of the asset will be subject to a different depreciation rate. Management believes that 60 million to 70 million British pounds (approximately $104 million to $121 million) represents a worst-case scenario for this liability.

The leases are legally defeased because the Company has made up-front payments to independent third-party banks in consideration for which these banks have assumed liability to the lessor equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, the Company receives rental rebates. Conversely, if actual interest rates are less than the assumed interest rates, the Company pays rentals in excess of the defeased rental payments. Over the last several years, the actual interest rates have been below the assumed interest rates. Prior to November 1, 2003, the Company had deferred a portion of a deferred gain (see Note 2 — UK leases) representing the net present value of additional required rental payments as of the inception of each lease. Such deferred gain was amortized over the terms of the leases. Effective November 1, 2003, the Company adopted fresh-start reporting and recorded a liability equal to the fair value of the future additional required rental payments based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, 24.6 million British pounds (approximately $47.2 million) at December 31, 2004 and 22.0 million British pounds (approximately $38.1 million) at December 31, 2005.

At December 31, 2005, interest rates were below the assumed interest rates. Based on forward market rates for Sterling LIBOR, the net present value, using an 8% per annum discount rate, of the additional required rental payments aggregated 31.5 million British pounds (approximately $54.5 million) as of December 31, 2005. Of this amount, 1.2 million British pounds (approximately $2.0 million) was accrued at December 31, 2005, in addition to the remaining fresh-start liability as described above.

Additional required rental payments were $7.2 million for each of the years ended December 31, 2005 and 2004, $4.9 million for the two months ended December 31, 2003 and $1.5 million for the ten months ended October 31, 2003.

Brazil Service Tax Claim.

The Company has an ongoing appeal process in Brazil related to municipal services tax ("ISS"), whether the Company is actually liable for ISS taxes and, if it is liable for such taxes, to which municipality such taxes should be paid (municipalities levy ISS tax at different rates). The appeal relates to the period 1998 through 2001 and the potential additional exposure for this period is $8.5 million. The Company is subject to additional exposure for subsequent periods of up to $29.9 million (including potential interest and penalties). ISS is a service tax, and the Company's primary view is that licensing of multi-client data should be treated as rental of an asset rather than a service, and therefore not subject to ISS. Management's assessment is that it is reasonably possible, but not probable, that this liability will materialize. Thus no accrual has been recognized.

NOTE 21 — Income Taxes

The expense (benefit) for income taxes from continuing operations consists of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Current taxes:				
Norwegian	$ 519	$ (5)	$ 394	$ 6,639
Foreign	10,343	20,761	1,558	15,373
Deferred taxes:				
Norwegian	—	24,534	(1,575)	2,025
Foreign	10,965	2,729	(4,226)	(3,943)
Total	$21,827	$48,019	$(3,849)	$20,094
Classification in consolidated statements of operations:				
Income tax expense (benefit)	21,827	48,019	(3,849)	21,911
Fresh start adoption	—	—	—	(1,817)
Total income tax expense (benefit)	$21,827	$48,019	$(3,849)	$20,094

The net expense (benefit) for the years ended December 31, 2005 and 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003 includes $224.7 million, $41.0 million, $3.1 million and $182.9 million, respectively, in valuation allowances related to deferred tax assets (see table below).

The net expense (benefit) for the years ended December 31, 2005 and 2004, and the ten months ended October 31, 2003 includes $(2.7) million, $9.5 million and $2.0 million, respectively, of provisions related to the resolution of uncertainties regarding outstanding tax issues. The total accrued amount related to contingent tax liabilities as of December 31, 2005 was $22.3 million, of which $3.1 million was recorded as income taxes payable and $19.2 million was recorded as other long-term liabilities. As of December 31, 2004, such amount totaled $29.9 million, of which $5.3 million was recorded in income taxes payable and $24.6 million was recorded as other long-term liabilities.

The Company evaluates the need for valuation allowances related to its deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. A valuation allowance, by tax jurisdiction, is established when it is more likely than not that all or some portion of deferred tax assets will not be realized. During 2005, the Company concluded that certain valuation allowances are no longer necessary as available evidence, including recent accumulated profits and estimates of projected near term future taxable income, supported a more-likely-than-not conclusion that a portion of the related deferred tax assets will be realized. As a result the Company released a portion of its valuation allowance, resulting in recognition of deferred tax assets of $20.0 million as of December 31, 2005.

Changes in valuation allowance are as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Balance at the beginning of the period	$405,285	$368,550	$365,439	$182,581
Current year additions	224,651	41,021	3,111	182,858
Decrease of valuation allowance from utilization and recognition of pre-reorganization deferred tax assets	(27,114)	(4,286)	—	—
Change related to other comprehensive income, sale of subsidiaries and minority interests	2,151	—	—	—
Balance at the end of the period	$604,973	$405,285	$368,550	$365,439

Current year additions to the valuation allowance relate to increases in tax losses carried forward and tax deductible temporary differences where the Company evaluated that it is more likely than not that the relevant deferred tax assets will not be recognized in future periods. Current year additions to the valuation allowance also include amounts related to deferred tax assets resulting from additional pre-reorganization tax loss carryforwards identified in 2005. There was a decrease of valuation allowance related to the utilization of tax benefits from pre-reorganization temporary differences and losses carried forward (for which a valuation allowance was provided at the date of reorganization) of $27.1 million, resulting in a corresponding decrease of intangible assets for the year ended December 31, 2005. The $27.1 million consisted of $7.1 million current year utilization and $20.0 million related to change in judgment about the estimated future utilization of deferred tax assets. The aggregate reduction to intangible assets consisted of reductions of $25.3 million to multi-client library, $1.3 million to other intangible assets and $0.5 million to other long-lived assets (see Notes 10, 11 and 12). Of the total valuation allowance as of December 31, 2005, $390.0 million relates to pre-reorganization amounts and will, if the related deferred tax assets are subsequently recognized, be allocated to reduce intangible assets existing at fresh-start (identified as multi-client library, other intangible assets and certain favorable lease contracts (included in other long-lived assets)) or directly to shareholders' equity if all intangible assets existing at fresh-start have been reduced to zero.

The expense (benefit) for income taxes from continuing operations differs from the amounts computed when applying the Norwegian statutory tax rate to income (loss) before income taxes as a result of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Income (loss) from continuing operations before income taxes, minority interest and cumulative effect of change in accounting principles:				
Norwegian	$(103,101)	$(125,179)	$(16,755)	$ 623,654
Foreign	241,071	35,421	3,198	(46,052)
Total	137,970	(89,758)	(13,557)	577,602
Norwegian statutory rate	28%	28%	28%	28%
Expense (benefit) for income taxes at statutory rate	38,632	(25,132)	(3,796)	161,729
Increase (reduction) in income taxes from:				
Foreign earnings taxed at other than statutory rate	(4,415)	(7,612)	(440)	(2,057)
Petroleum surtax(a)	(1,415)	12,343	(1,619)	5,908
Non-taxable gain on sale of subsidiary	(40,422)	—	—	—
Non-taxable gain on debt discharge	—	—	—	(351,078)
Other	5,655	3,047	—	—
Gain (loss) from local currency other than reporting currency	2,621	(2,578)	(1,495)	372
Current year realization of uncertain tax position not recognized in prior years	(82,556)	—	—	—
Non-creditable foreign taxes and other permanent items	27,728	26,930	390	22,362
Change in temporary differences to intangible assets due to utilization of pre-reorganization deferred tax assets (circle effect)	(8,760)	—	—	—
Deferred tax asset valuation allowance	84,759	41,021	3,111	182,858
Total income tax expense (benefit)	$ 21,827	$ 48,019	$ (3,849)	$ 20,094

(a) Pertra's income from oil activities on the Norwegian Continental Shelf is taxed according to the Norwegian Petroleum Tax Law, which includes a surtax of 50% in addition to the Norwegian corporate tax of 28%.

Deferred tax assets and liabilities are summarized as follows:

	December 31,			
	2005		2004	
	Asset	Liability	Asset	Liability
	(In thousands of dollars)			
Current assets and liabilities	$ (4,166)	$ 19,525	$ (3,036)	$ 1,038
Property, equipment and other long-lived assets	(137,822)	509	(23,384)	37,002
Tax losses carried forward	(447,799)	—	(262,458)	—
Deferred gain (loss)	(19,606)	22,527	(57,721)	32,971
Tax credits	(3,083)	—	(2,893)	—
Expenses deductible when paid	(47,503)	—	(84,853)	—
Other temporary differences	(6,003)	—	(6,072)	—
Total deferred tax (assets) liabilities before valuation allowance	(665,982)	42,561	(440,417)	71,011
Deferred tax asset valuation allowance	604,973		405,285	
Deferred tax (assets) liabilities	$ (61,009)	$ 42,561	$ (35,132)	$71,011
Net deferred tax (assets) liabilities — Norwegian		(20,000)		35,514
Net deferred tax (assets) liabilities — Foreign		1,552		365
Net deferred tax (assets) liabilities		$(18,448)		$35,879
Classification in the consolidated balance sheets:				
Short-term deferred tax liabilities		$ 1,055		$ 761
Long-term deferred tax assets		(20,000)		—
Long-term deferred tax liabilities		497		35,118
Net deferred tax (assets) liabilities		$(18,448)		$35,879

Tax losses carried forward in Norway of $1,166.0 million, in the UK of $282.2 million, and in Singapore, Brazil and Australia totaling $52.1 million can be carried forward indefinitely. U.S. tax losses carried forward of $63.9 million expire between 2019 and 2026.

The Company does not provide Norwegian taxes on unremitted earnings of certain international operations, which reflect full provision for non-Norwegian income taxes, as these earnings are expected to be reinvested outside of Norway indefinitely. The company has not calculated the tax effect associated with these unremitted earnings as it is not practicable to do so.

The Company has received a tax claim from the tax authority in Singapore relating to the years 1998 through 2002 based on the assertion that tax deductions for expenses related to investments in the multi-client data library would not be allowed. The possible additional exposure is $26.8 million, of which an assessment of $7.1 million has been issued for fiscal year 1998. Until 2003, the multi-client library was not automatically subject to tax allowances if classified as an intangible asset. The Company has filed tax returns claiming tax deductions for amortization of the multi-client library as included in the financial statements. The Company is currently preparing an appeal to the Ministry of Finance against the tax claim, which would assert that costs incurred when acquiring data under an exclusive license contract are tax deductible, while costs incurred when acquiring data under a non-exclusive multi-client license contract are not tax deductible. Management's assessment is that it is reasonably possible, but not probable, that the tax authority's view will prevail.

Penalties of up to 17% of the $7.1 million that has already been assessed will accrue in 2006 if the Company does not pay the additional tax and is unsuccessful in claiming amortization.

Until January 1, 2002, a foreign subsidiary was included in the Norwegian shipping tax regime. No deferred taxes were recognized on unremitted earnings in this subsidiary prior to the withdrawal from the regime as these earnings at that time were expected to be reinvested indefinitely within the regime. A subsequent decision in 2003 to exit with effect from 2002 resulted in recognition of deferred tax liabilities of $78.8 million. The Norwegian Central Tax Office ("CTO") has not yet finalized the 2002 tax assessment in relation to withdrawal from the Norwegian shipping tax regime. The pending issue is related to fair value of the vessels involved. The Company based such exit values on third party valuations, while the CTO has raised the issue whether the Company's book values at December 31, 2001, would be more appropriate as basis for computing the tax effects of the exit. Any increase of exit values will result in an increase of taxable exit gain and a corresponding increase in basis for future tax depreciation. The Company estimates that if the CTO position is upheld, taxes payable for 2002, without considering mitigating actions, could increase by up to $24 million. The Company believes that its calculation basis for exit has been prepared using acceptable principles and will contest any adjustment to increase taxes payable.

NOTE 22 — Pension Obligations

Defined Benefit Plans.

The Company has historically had defined benefit pension plans for substantially all of its Norwegian and UK employees, with eligibility determined by certain period-of-service requirements. In Norway these plans are generally funded through contributions to insurance companies. In the UK, the plans are funded through a separate pension trust. It is the Company's general practice to fund amounts to these defined benefit plans at rates that are sufficient to meet the applicable statutory requirements. As of January 1, 2005, a part of the Norwegian plans were settled eliminating future spouse and child-survivor benefits. Accrued benefits as of that date were settled with annuity contracts and employees eligible under these plans received a paid-up pension for earned funds covering the spouse and child portion up to December 31, 2004. In addition the Norwegian defined benefit plans were closed for further entries and new defined contribution plans established for new employees (see separate section below). At December 31, 2005, 955 employees were participating in the defined benefit plans.

Pension cost for disposed subsidiaries are included for the period up to the sales closing date.

Reconciliation of the plans' aggregate projected benefit obligations and fair values of assets are summarized as follows:

Change in projected benefit obligations (PBO):

	December 31,	
	2005	2004
	(In thousands of dollars)	
Projected benefit obligations (PBO) at beginning of year	$117,796	$101,855
Service cost	9,445	10,198
Interest cost	5,540	5,145
Employee contributions	1,033	968
Payroll tax	24	178
Actuarial (gain) loss, net	11,166	(9,532)
Benefits paid	(1,382)	(1,212)
Exchange rate effects	(15,402)	10,196
Projected benefit obligations (PBO) at end of year	$128,220	$117,796

Change in pension plan assets:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Fair value of plan assets at beginning of year	$71,565	$53,332
Adjustment at beginning of year	531	(1,214)
Return on plan assets	4,878	4,130
Employer contributions	9,848	8,383
Employee contributions	1,033	968
Benefits paid	(1,382)	(1,212)
Exchange rate effects	(8,237)	7,178
Fair value of plan assets at end of year	$78,236	$71,565

The aggregate funded status of the plans and amounts recognized in the Company's consolidated balance sheets are summarized as follows:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Funded status	$(49,984)	$(46,232)
Unrecognized actuarial (gain) loss	9,892	(6,021)
Unrecognized prior service cost	(5,140)	—
Additional minimum liability	(211)	(219)
Net amount recognized as pension liability (Note 14)	$(45,443)	$(52,472)

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $111.4 million and $104.3 million as of December 31, 2005 and 2004, respectively.

Net periodic pension costs for the Company's defined benefit pension plans are summarized as follows.

	Successor Company			Predecessor Company
	Years Ended December 31, 2005	Years Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Service cost	$ 9,445	$10,198	$1,204	$ 7,145
Interest cost	5,540	5,145	1,207	3,247
Expected return on plan assets	(4,878)	(4,130)	(819)	(2,977)
Amortization of plan changes	(335)	—	—	—
Amortization of actuarial loss (gain)	(169)	16	(80)	403
Adjustment to actuarial (gain) loss, plan changes	1,080	—	—	—
Amortization of prior service cost	—	—	—	3
Amortization of transition obligation	—	—	—	17
Adjustment to minimum liability	—	198	—	—
Administration cost	105	99	—	—
Payroll tax	1,043	949	266	397
Net periodic pension cost	$11,831	$12,475	$1,778	$ 8,235

Plans in which the accumulated benefit obligation exceeds plan assets are as follows:

	December 31, 2005	December 31, 2004
	(In thousands of dollars)	
Projected benefit obligation (PBO)	$127,939	$112,727
Accumulated benefit obligation (ABO)	111,172	100,167
Fair value of plan assets	77,913	67,147

Assumptions used to determine net periodic pension costs:

	Years Ended December 31,					
	2005		2004		2003	
	Norway	UK	Norway	UK	Norway	UK
Discount rate	4.8%	5.3%	5.3%	5.3%	6.0%	5.3%
Return on plan assets	5.8%	7.5%	6.3%	7.5%	7.0%	7.5%
Compensation increase	3.2%	3.0%	3.0%	3.0%	3.0%	4.7%
Annual adjustment to pensions	3.2%	3.0%	3.0%	3.0%	3.0%	3.0%

Assumptions used to determine benefit obligations at end of years presented:

	December 31, 2005		December 31, 2004	
	Norway	UK	Norway	UK
Discount rate	4.3%	4.8%	5.3%	5.3%
Compensation increase	3.2%	3.2%	3.0%	3.0%

The discount rate assumptions used for calculating pensions reflect the rates at which the obligations could be effectively settled. Observable long-term rates on governmental bonds are used as a starting point and matched with the Company's expected cash flows under the Norwegian plans. Observable long-term rates on corporate bonds are used for the UK plans. The expected long-term rate of return on plan assets is based on historical experience and by evaluating input from the trustee managing the plan's assets.

The Company's pension plan asset allocation at December 31, 2005 and 2004, by asset category, are presented by major plan group as follows:

	December 31,			
	2005		2004	
	Norway	UK	Norway	UK
	(In thousands of dollars)			
Fair value of plan assets	$38,268	$39,968	$40,111	$31,454
Debt securities	62%	—	69%	—
Equity securities	23%	100%	16%	92%
Real estate	12%	—	12%	—
Other	3%	—	3%	8%
Total	100%	100%	100%	100%

Average target allocations for Norwegian plan assets are 15-30% in equity securities, 50-70% in debt securities, 10-15% in real estate and 3-10% in other. Maturities for the debt securities at December 31, 2005, range from two weeks to 28 years with a weighted average maturity of 4.6 years. Weighted average duration for the debt securities is 3.6 years.

Management of plan assets must comply with applicable laws and regulations in Norway and the UK where the Company provides defined benefits plans. Within constraints imposed by laws and regulations, and given the assumed pension obligations and future contribution rates, the majority of assets are managed actively to obtain a long-term rate of return that at least reflects the chosen investment risk.

The Company expects to contribute approximately $7.0 million to its defined benefit pension plans in 2006. Total pension benefit payments expected to be paid to participants from the plans are as follows:

	(In thousands of dollars)
2006	$1,166
2007	1,371
2008	1,545
2009	1,719
2010	1,320
2011 through 2015	15,374

Defined Contribution Plans.

Substantially all employees not eligible for coverage under the defined benefit plans in Norway and the UK are eligible to participate in pension plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans.

As described above under "Defined Benefit Plans," as of January 1, 2005 the Company closed the Norwegian defined benefit plans for further entries and new defined contribution plans were established for new employees. The Company's contributions to these plans for the year ended December 31, 2005 totaled $0.2 million.

Under the Company's U.S. defined contribution 401(k) plan, essentially all U.S. employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 100% of compensation, subject to IRS and plan limitations, on a pre-tax basis, with a 2005 statutory cap of $14,000 ($18,000 for employees over 50 years). Employee pre-tax contributions are matched by the Company as follows: the first 3% are matched at 100% and the next 2% are matched at 50% of compensation. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $1.3 million and $1.2 million for the years ended December 31, 2005 and 2004, $0.2 million for the two months ended December 31, 2003 and $1.2 million for the ten months ended October 31, 2003. Contributions to the plan by employees for these periods were $3.3 million, $3.1 million, $0.6 million and $2.7 million, respectively.

Aggregate employer and employee contributions under the Company's other plans for the years ended December 31, 2005 and 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003, totaled $0.6 million and $0.3 million (2005), $0.8 million and $0.4 million (2004), $0.1 million and $0.1 million (two months 2003) and $2.1 million and $0.3 million (ten months 2003).

NOTE 23 — Share Based Compensation Plans

In connection with the restructuring of the Company in 2003, all shares in the Company were cancelled (see Notes 1 and 3 for additional information) and all agreements relating to share options for the Company's key employees and directors were cancelled. No new option agreements have been established since the restructuring. During the period in which the share-based compensation plan was active, the exercise price of each award equaled the market price of the Company's shares on the grant date. The vesting period for granted options ranged from approximately three years to approximately three and one-half years. Once vested, the exercisable life of the options was generally a two-year period, with certain options granted during 2000 and thereafter exercisable over a three-year period. The Company used the intrinsic value method to account for this stock-based employee compensation.

A summary of the status of the Company's share-based compensation plans as of December 31, 2003 is summarized as follows:

	December 31, 2003	
	Options	Weighted Average Exercise Price
Outstanding at beginning of year	4,973.5	NOK135
Forfeited/cancelled	(4,973.5)	NOK135
Outstanding at December 31, 2003	—	—

If the compensation cost for the share-based compensation plans had been determined based on the fair values of the options awarded at the grant dates, consistent with the provisions of SFAS 123, the net income (loss) and earnings (loss) per share would have been affected on a pro forma basis as indicated below:

	Predecessor Company
	Ten Months Ended October 31, 2003
	(In thousands of dollars, except for share amounts)
Net income, as reported	$557,045
Deduct: Total share-based compensation expense determined under the fair value based method for all awards, net of related tax effect	(5,105)
Pro forma, net income	$551,940
Net income per share:	
Basic and diluted — as reported	$ 5.39
Basic and diluted — pro forma	$ 5.34

NOTE 24 — Acquisitions and Dispositions

In 2002, the Company sold its Production Services (formerly Atlantic Power Group) subsidiary to Petrofac Limited. The Company is eligible to receive an additional consideration of $2.5 million upon the occurrence of certain contingent events through 2010.

In February 2003, the Company sold its Atlantis oil and gas activities to Sinochem and received proceeds and reimbursements aggregating $59.2 million. The Company was entitled to receive up to $25.0 million in additional, contingent proceeds, which agreement was amended in June 2005. In accordance with the amended agreement, the Company may receive a maximum of $10.0 million in contingent proceeds upon the occurrence of certain contingent events, which currently has not been recognized.

In December 2003, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. for a deferred compensation of approximately $1.8 million, payable in 2004 through 2007, for which payments were received in December 2005 and 2004. The Company may also receive additional contingent proceeds based on performance of the company through 2006. As of December 31, 2005, the Company had not received any such contingent proceeds. The Company recognized no net gain or loss on the sale of Tigress.

In March 2005, the Company sold its wholly owned oil and natural gas subsidiary Pertra AS to Talisman Energy (UK) Ltd. for an initial sales price of approximately $155 million. Pertra AS has been renamed Talisman Production Norge AS. The Company recognized a $149.8 million gain from the sale, including the $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg*, recognized as net gain on sale of subsidiaries. As part of the transaction, the Company is entitled to receive additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006, we received $8.1 million, representing the 2005 portion of the contingent consideration. The Company accrued this amount in December 2005 and recognized the amount as additional gain on the 2005 sale (see Note 4). The Company also granted an option enabling Talisman to change the termination clause with respect to PL038. The option expired on February 1, 2006 without being exercised. Assets and liabilities relating to Pertra as of December 31, 2004 are shown below, while the results of operations and capital expenditures for the periods presented up to March 1, 2005 are presented as a separate segment in our consolidated statements of operations (see Note 27). The operations of Pertra are not presented as discontinued operations due to continuing involvement through the charter of *Petrojarl Varg*.

In August 2005, the Company entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS to Reservoir Consultants Holding AS ("RCH"), which is controlled by a group of former PGS employees. RCH has the option to sell the shares back to the Company for an amount equal to the consideration (approximately $0.5 million), which option expires 12 months from completion date (August 31, 2005). The Company has recorded an estimated loss of $1.5 million for this transaction, recognized in net gain on sale of subsidiaries (see Note 4.) In addition the Company recorded assets and liabilities of business transferred under the contractual arrangement aggregating $3.5 million gross. Such assets and liabilities are recognized in other current assets and accrued expenses (see Notes 8 and 13).

The results of operations, net assets and cash flows for Tigress have been presented as discontinued operations, and are summarized as follows for the years presented:

	Successor Company	Predecessor Company
	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)	
Revenues	$ 137	$ 1,107
Operating expenses before depreciation, amortization, impairment and other operating (income) expense, net	(264)	(2,433)
Depreciation and amortization	—	(707)
Other operating (income) expense, net	—	(512)
Total operating expenses	(264)	(3,652)
Operating profit (loss)	(127)	(2,545)
Interest expense and other financial items, net	24	(1,237)
Income (loss) before income taxes	$(103)	$(3,782)
Capital expenditures of discontinued operations	$ —	$ 118

A reconciliation of income (loss) before income taxes, as reported above, and income (loss) from discontinued operations, net of tax, as presented in the Consolidated Statements of Operations, is as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
Income (loss) from discontinued operations before income taxes	$ —	$ —	$(103)	$(3,782)
Loss on disposal	—	—	(32)	—
Additional proceeds	500	3,048	—	1,500
Loss from discontinued operations, net of tax	$500	$3,048	$(135)	$(2,282)

Operating expenses relating to discontinued operations includes corporate management fees based on actual charges to these entities. For continuing operations, such fees are presented in the segment for Reservoir/Shared Services/Corporate (see Note 27). Allocation of interest expense to discontinued operations is based on actual interest charged to the respective entities.

The operations of Pertra are presented as a separate segment in our consolidated statements of operations (see Note 27). Assets and liabilities relating to Pertra as of December 31, 2004 were as follows:

	December 31, 2004
	Pertra
	(In thousands of dollars)
Cash and cash equivalents	$ 13,423
Accounts receivable, net	7,406
Other current assets	15,916
Property and equipment, net	937
Oil and natural gas assets, net	70,940
Other long-lived assets	12,024
Total assets	$120,646
Accounts payable	$ 1,624
Accrued expenses	8,720
Deferred tax liabilities, current	761
Other long-term liabilities	39,942
Deferred tax liabilities, long-term	34,752
Total liabilities	$ 85,799

Subsequent Events.

In February 2006, the Company announced a proposed joint venture with Teekay Shipping Corporation to develop new FPSO projects. We expect to finalize the arrangements for the joint venture during the second quarter of 2006.

As described above, the Company may receive $10 million in additional contingent proceeds, upon the occurrence of certain contingent events, from the sale of Atlantis in 2003. At December 31, 2005, the Company had not accrued for these proceeds. In March 2006, the Company received confirmation of the occurrence of certain of these events that entitle the Company to receive $6 million, of which $3 million was received in March 2006.

On March 27, 2006, the Company's Board of Directors authorized proceeding with a demerger plan under Norwegian law to separate its geophysical and production businesses into two independently listed companies and calling an extraordinary general meeting of its shareholders to vote on the transaction, to be held on April 28, 2006.

Under the proposed demerger, the Company's subsidiary companies that conduct its production business, and the assets, rights and liabilities related to the production business, will be transferred to a wholly owned subsidiary named Petrojarl ASA. The Company's subsidiary companies that conduct its geophysical business, and the assets, rights and liabilities related to the geophysical business, will be retained under Petroleum Geo-Services ASA.

When the separation is completed, each holder of the Company's ordinary shares will receive one ordinary share of Petrojarl for each of its shares held and each holder of American Depositary Shares ("PGS ADSs") representing the Company's ordinary shares will receive one newly issued American Depositary Share representing an ordinary share in Petrojarl ("Petrojarl ADSs") for each PGS ADS held. The Company intends to apply for a listing of the ordinary shares of Petrojarl ASA on the Oslo Stock Exchange. The Company does not intend to list the Petrojarl ordinary shares or Petrojarl ADSs in the U.S.

Immediately after consummation of the demerger, PGS ASA would hold shares in Petrojarl representing a 19.99% interest in Petrojarl and the Petrojarl shares issued to the holders of the Company's shares and the PGS ADSs would represent the remaining 80.01% interest in Petrojarl. Subject to prevailing market conditions and other factors, PGS ASA expects to sell the shares in Petrojarl in a public offering in conjunction with the consummation of the separation and demerger.

If the demerger plan is approved by the requisite two-third vote of the Company's shareholders and the conditions precedent to consummation of the demerger are satisfied, or where applicable waived, the Company currently expect the demerger to be consummated in July 2006.

After completion of the demerger, PGS ASA will continue the Company's geophysical business and hold its assets, rights and liabilities.

Upon consummation of the separation, the Company expects that Petrojarl will have a new $425 million five year borrowing facility and will initially borrow $325 million under the facility. The proceeds from the initial borrowing, together with any proceeds from any sale of all or any part of the Petrojarl shares retained by PGS ASA, will be used by PGS ASA for repayment of existing debt or other purposes. As part of the separation transaction, Petrojarl will receive cash and cash equivalents of approximately $50 million and will have approximately $275 million of net interest-bearing debt immediately following consummation of the separation.

In connection with the demerger, the Company has entered into other agreements, subject to final documentation, either as part of the proposed demerger plan or otherwise, to facilitate the demerger. For the Company's UK leases on three of its Ramform seismic vessels and the production equipment for the

Ramform Banff, the Company has entered into agreements, subject to final documentation, with the lessors providing for certain options with respect to the termination of the leases at reduced termination fees, subject to completion of the demerger. If all of such leases were terminated, the Company would be required to pay termination fees of up to 13 million British pounds (approximately $23 million). Upon termination, the Company and, in the case of *Ramform Banff*, Petrojarl would become the owner of the assets and avoid any additional rental payments relating to these UK leases. In addition, the Company has reached an agreement, subject to final documentation, with the operator of *Petrojarl Foinaven* to provide the benefit of financial covenants that would apply to Petrojarl following the demerger and to make other amendments to the existing contractual arrangements, in each case subject to completion of the demerger and certain other conditions. The Company will provide more detailed information related to the separation and demerger, as well as the other agreements, in a shareholder information statement prior to the extraordinary general meeting of its shareholders called to consider the separation and demerger, which the Company expects to occur in April 2006.

The demerged Production business will be presented as held-for-sale (discontinued operations) in the consolidated financial statements from the date of board approval of the demerger. In addition, historical financial information of the Pertra operations will be presented as discontinued from the same date, as the continued business relations with Pertra related to *Petrojarl Varg* will be discontinued with the demerger of the Production business.

NOTE 25 — Related Party Transactions

At December 31, 2003 the Company owned 50% of the shares in Geo Explorer AS and had one vessel on charter from that company. The Company also held 100% of the shares in Walther Herwig AS (until December 11, 2003, the Company held 50% of the shares, but increased its shares as Walter Herwig AS was de-merged) and chartered three vessels from that company in 2003. Total lease expense recognized during the two months ended December 31, 2003 and the ten months ended October 31, 2003 on these vessels was $1.1 million and $6.4 million, respectively. There were no lease expenses for the years ended December 31, 2005 and 2004.

As of December 31, 2005, the Chairman of the Board, Jens Ulltveit-Moe, through Umoe AS, controlled a total of 3,037,332 shares in PGS. Jens Ulltveit-Moe also has a majority ownership interest in Knutsen OAS Shipping AS ("Knutsen"). Knutsen is chartering the MT *Nordic Svenita* and was also chartering the MT *Nordic Yukon* up to 2003 and paid $10.0 million, $10.3 million and $20.1 million to the Company under time charter contracts for the vessels in 2005, 2004 and 2003, respectively. The Company charters the vessels from an independent third party. The vessels were chartered by the Company to provide shuttle services for the Banff field, but in 2001 were chartered to Knutsen on terms approximating the Company's terms under the third-party lease, due to low production on the Banff field. The vessel MT *Nordic Yukon* was redelivered by PGS to the vessel owner in November 2003. In addition, PGS has a contract of affreightment with Knutsen for transporting crude oil relating to the Banff field and paid $1.2 million, $0.7 million and $2.4 million to Knutsen under this contract in 2005, 2004 and 2003, respectively. Mr. Ulltveit-Moe was also the Chairman of Unitor ASA until August 2005, a company that from time to time provides the Company with equipment for its vessels.

Subsequent Event.

In January 2006 the Company entered into an agreement to purchase the shuttle tanker MT *Rita Knutsen* for $35 million from Knutsen OAS Shipping AS. The transaction was completed March 9, 2006. The Company considers the vessel to be a possible FPSO solution for several upcoming projects, and the Company intends to begin a conversion when a firm contract for the ship is secured. The vessel will be operated by Knutsen OAS Shipping AS under a bareboat charter agreement until a decision to start conversion is made. Jens Ulltveit-Moe did not participate in any Board discussions relating to this transaction.

NOTE 26 — Investments in Associated Companies

Income from associated companies accounted for using the equity method is as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Corporations and limited partnerships:				
Geo Explorer AS	$ (2)	$ 26	$119	$1,425
Atlantic Explorer (IoM) Ltd.	(5)	(80)	—	—
Ikdam Production, SA	243	722	81	162
Triumph Petroleum	—	—	—	(813)
General partnerships	40	—	—	—
Total	$276	$668	$200	$ 774

Investments and advances to associated companies accounted for using the equity method are as follows:

	Book Value December 31, 2004	Share of Income 2005	Paid-In Capital/ (Dividends) 2005	Equity Transactions 2005(a)	Book Value December 31, 2005	Ownership Percent As of December 31, 2005
Corporations and limited partnerships:						
Ikdam Production, SA	$5,411	$243	$ —	$ (1)	$5,653	40.0%
Geo Explorer AS	182	(2)	—	(15)	165	50.0%
Atlantic Explorer (IoM) Ltd.	32	(5)	—	(3)	24	50.0%
Valiant Intern. Petroleum Ltd.	—	—	68	—	68	24.6%
General partnerships	95	40	(66)	(44)	25	
Total	$5,720	$276	$ 2	$(63)	$5,935	

(a) Includes foreign currency translation differences.

NOTE 27 — Segment and Geographic Information

The Company, after the sale of Pertra AS in March 2005, manages its business in three segments as follows:

- *Marine Geophysical*, which consists of streamer seismic data acquisition, marine multi-client library and data processing;
- *Onshore*, which consists of all seismic operations on land and in shallow water and transition zones, including onshore multi-client library;
- *Production*, which owns and operates four harsh environment FPSOs in the North Sea; and

Pertra AS, a small oil and natural gas company, was sold March, 2005 (see Notes 4 and 24). Revenues and expenses, assets and liabilities are included in the consolidated statements through February 2005 and in the comparative numbers for the years presented. The operations of Pertra are not presented as discontinued operations due to continuing involvement through the lease of *Petrojarl Varg.*

The Company manages its Marine Geophysical segment from Lysaker, Norway, its Onshore segment from Houston, Texas, and its Production segment from Trondheim, Norway.

The principal markets for the Production segment are the UK and Norway. The Marine Geophysical and Onshore segments serve a worldwide market. Customers for all segments are primarily composed of major multi-national, independent and national or state-owned oil companies. Corporate overhead has been presented under Reservoir/Shared Services/Corporate. Significant charges, which do not relate specifically to the operations of any one segment, such as debt refinancing and restructuring costs, are also presented as Reservoir/Shared Services/Corporate. Information related to discontinued operations during any period presented has been separately aggregated. Affiliated sales are made at prices that approximate market value. Interest and income tax expense are not included in the measure of segment performance.

Revenues by Segment.

The table below presents our mix of revenues for the periods presented:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Marine Geophysical:				
Contract	$ 424,192	$ 297,749	$ 48,273	$302,451
Multi-client pre-funding	40,006	30,535	6,510	43,187
Multi-client late sales	218,781	203,397	36,786	123,435
Other	41,703	39,124	7,813	31,040
Total Marine Geophysical	724,682	570,805	99,382	500,113
Onshore:				
Contract	122,415	110,288	18,442	106,324
Multi-client pre-funding	16,148	12,761	1,807	14,636
Multi-client late sales	13,976	10,112	1,210	8,005
Total Onshore	152,539	133,161	21,459	128,965
Production:				
Petrojarl I	53,394	61,303	11,086	58,529
Petrojarl Foinaven	89,191	96,595	18,726	93,373
Ramform Banff	46,483	51,509	6,572	38,616
Petrojarl Varg	89,920	87,133	8,604	59,191
Other	1,689	1,662	241	349
Total Production	280,677	298,202	45,229	250,058
Reservoir/Shared Services/Corporate	19,418	20,852	4,957	16,243
Elimination inter-segment revenues	(17,732)	(77,686)	(8,200)	(45,612)
Total revenues services	1,159,584	945,334	162,827	849,767
Revenues products — Pertra	36,742	184,134	9,544	112,097
Total revenues	$1,196,326	$1,129,468	$172,371	$961,864

Additional segment information for the periods presented is summarized as follows:

	Marine Geophysical	Onshore	Production	Pertra	Reservoir/ Shared Services/ Corporate	Elimination of Inter-Segment Items	Total
	(In thousands of dollars)						
Depreciation and amortization:							
2005 (Successor)	$172,349	$ 31,665	$ 44,064	$ 6,710	$ 4,567	$ —	$ 259,355
2004 (Successor)	241,712	39,885	44,561	38,965	3,239	—	368,362
2003 (Successor — two months)	39,351	6,224	8,112	743	1,269	—	55,699
2003 (Predecessor — ten months)	191,215	29,425	43,418	30,826	6,692	—	301,576

	Marine Geophysical	Onshore	Production	Pertra	Reservoir/ Shared Services/ Corporate	Elimination of Inter-Segment Items	Total
	(In thousands of dollars)						
Segment operating profit:							
2005 (Successor)	$150,229	$ (9,803)	$ 43,491	$ (1,507)	$ (25,789)	$ 924	$ 157,545
2004 (Successor)	(34,980)	(4,535)	77,769	28,120	(20,986)	(1,593)	43,795
2003 (Successor — two months)	1,772	1,778	11,878	(3,198)	(476)	—	11,754
2003 (Predecessor — ten months)	41,782	19,741	66,876	17,236	(19,475)	—	126,160
Impairment of long-lived assets:							
2005 (Successor)	$ 4,575	$ —	$ —	$ —	$ —	$ —	$ 4,575
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	89,598	5,085	328	—	—	—	95,011
Net (gain) on sale of subsidiaries:							
2005 (Successor)	$ —	$ —	$ —	$ —	$(156,382)	$ —	$ (156,382)
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	—	—	—	—	—	—	—
Other operating (income) expense, net:							
2005 (Successor)	$ (8,847)	$ —	$ —	$ —	$ (17,248)	$ —	$ (26,095)
2004 (Successor)	(13)	9	—	—	8,116	—	8,112
2003 (Successor — two months)	1,189	38	—	—	(175)	—	1,052
2003 (Predecessor — ten months)	8,107	266	—	—	12,951	—	21,324
Operating profit:							
2005 (Successor)	$154,501	$ (9,803)	$ 43,491	$ (1,507)	$ 147,841	$ 924	$ 335,447
2004 (Successor)	(34,967)	(4,544)	77,769	28,120	(29,102)	(1,593)	35,683
2003 (Successor — two months)	583	1,740	11,878	(3,198)	(301)	—	10,702
2003 (Predecessor — ten months)	(55,923)	14,390	66,548	17,236	(32,426)	—	9,825
Income (loss) from discontinued operations, net of tax:(a)							
2005 (Successor)	$ —	$ —	$ 500	$ —	$ —	$ —	$ 500
2004 (Successor)	—	—	3,048	—	—	—	3,048
2003 (Successor — two months)	(135)	—	—	—	—	—	(135)
2003 (Predecessor — ten months)	(3,782)	—	1,500	—	—	—	(2,282)
Cumulative effect of change in accounting principles, net of tax							
2005 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	(779)	—	3,168	—	—	—	2,389
Investment in associated companies:							
December 31, 2005	$ 278	$ —	$ 5,653	$ —	$ 4	$ —	$ 5,935
December 31, 2004	235	—	5,411	—	74	—	5,720
Total assets:							
December 31, 2005	$797,316	$ 98,823	$676,337	$ —	$ 145,096	$ —	$1,717,572
December 31, 2004	795,102	90,451	710,521	120,646	135,433	—	1,852,153

	Marine Geophysical	Onshore	Production	Pertra	Reservoir/ Shared Services/ Corporate	Elimination of Inter-Segment Items	Total
	(In thousands of dollars)						
Additions to long-lived tangible assets: (b)							
2005 (Successor)	$118,442	$ 21,055	$ 11	$ 103	$ 6,629	$ (83)	$ 146,157
2004 (Successor)	87,742	10,817	988	84,991	5,088	(114)	189,512
2003 (Successor — two months)	13,715	5,182	1,662	4,424	463	—	25,446
2003 (Predecessor — ten months)	71,299	21,965	(1,147)	29,741	1,349	—	123,207
Capital expenditures on discontinued operations: (a)							
2005 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	118	—	—	—	—	—	118

(a) Income (loss) from discontinued operations, net of tax, and capital expenditures on discontinued operations, included in segment data for Marine Geophysical and Production relates to Tigress and Production Services, respectively.

(b) Consists of cash investments in multi-client library and capital expenditures.

Reconciliation of segment operating profit, presented in the table above, to income (loss) before income tax expense (benefit) and minority interest, is as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Segment operating profit	$157,545	$ 43,795	$ 11,754	$ 126,160
Other segment allocated amounts (as presented in the table above):				
Impairment of long-lived assets	4,575	—	—	95,011
Net (gain) on sale of subsidiaries	(156,382)	—	—	—
Other operating (income) expense, net	(26,095)	8,112	1,052	21,324
Operating profit	335,447	35,683	10,702	9,825
Unallocated amounts:				
Income from associated companies	276	668	200	774
Interest expense	(96,356)	(110,811)	(16,870)	(98,957)
Debt redemption and refinancing costs	(107,315)	—	—	—
Other financial items, net	5,918	(10,861)	(4,264)	(1,472)
Gain on debt discharge	—	—	—	1,253,851
Fresh-start adoption	—	—	—	(532,268)
Cost of reorganization	—	(3,498)	(3,325)	(52,334)
Income (loss) before income tax expense (benefit) and minority interest	$137,970	$ (88,819)	$(13,557)	$ 579,419

Since the Company provides services worldwide to the oil and natural gas industry, a substantial portion of the property and equipment is mobile, and the respective locations at the end of the period (as listed in the table below, together with multi-client library and oil and natural gas assets) are not necessarily indicative of the earnings of the related property and equipment during the period. The geographic classification of income statement amounts listed below is based upon location of performance or, in the case of multi-client seismic data sales, the area where the survey was physically conducted.

Information by geographic region is summarized as follows:

	Americas	UK	Norway	Asia/Pacific	Africa	Middle East/ Other	Elimination of Inter-Segment Items	Total
	(In thousands of dollars)							
Revenue, external customers:								
2005 (Successor)	$311,496	$175,440	$306,158	$199,107	$139,317	$64,808	$ —	$1,196,326
2004 (Successor)	267,054	191,745	336,949	191,703	112,503	29,514	—	1,129,468
2003 (Successor — two months)	49,164	30,743	33,087	35,175	20,784	3,418	—	172,371
2003 (Predecessor — ten months)	270,095	181,595	235,663	82,980	124,601	66,930	—	961,864
Revenue, includes inter-segment:								
2005 (Successor)	$312,394	$176,053	$309,349	$199,826	$139,679	$65,186	$(6,161)	$1,196,326
2004 (Successor)	267,054	194,712	343,736	191,703	112,503	29,514	(9,754)	1,129,468
2003 (Successor — two months)	49,164	31,067	35,429	35,175	20,784	3,418	(2,666)	172,371
2003 (Predecessor — ten months)	270,095	183,371	238,543	82,980	124,601	66,930	(4,656)	961,864
Total assets:								
December 31, 2005	$302,774	$940,263	$380,898	$ 73,801	$ 10,663	$ 9,173	$ —	$1,717,572
December 31, 2004	343,484	927,172	469,675	79,873	21,211	10,738	—	1,852,153
Capital expenditures (cash):								
2005 (Successor)	$ 19,183	$ 63,679	$ 5,195	$ 1,579	$ —	$ 854	$ —	$ 90,490
2004 (Successor)	7,955	40,812	96,813	1,975	—	817	—	148,372
2003 (Successor — two months)	5,464	1,005	9,294	222	—	—	—	15,985
2003 (Predecessor — ten months)	6,261	6,155	27,952	136	—	1,561	—	42,065

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2005, 2004 and 2003.

For the years ended December 31, 2005, 2004 and 2003, customers exceeding 10% of the Company's total revenue were as follows (the table shows percentage of revenues accounted for by each of such customers, and the segments that had sales to the respective customers are marked with X):

	Years Ended December 31,						
	2005		2004		2003		
	13%	10%	25%	10%	19%	12%	10%
Segments serving customer (each % in each year represents a separate customer):							
Marine Geophysical	X	X	X	X	X	X	X
Onshore		X					X
Production	X	X	X	X	X	X	
Pertra	X		X		X		
Reservoir/Shared Services/Corporate	X		X		X		

In certain of the regions where the Company operates, a significant share of its employees is organized in labor unions. Similarly the Company's operations in certain regions are members of employer unions. Therefore, the Company may be affected by labor conflicts involving such labor and employer unions.

NOTE 28 — Supplemental Cash Flow Information

Cash paid during the year includes payments for:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Interest, net of capitalized interest	$91,724	$106,731	$19,619	$120,162
UK lease, additional required rental payments (Note 20)	7,180	7,196	4,953	1,473
Income taxes	14,572	29,751	4,951	8,145

The Company entered into capital lease agreements for new equipment aggregating $0.7 million for the year ended December 31, 2005 and $0.6 million for the ten months ended October 31, 2003. There were no new capital lease agreements during the year ended December 31, 2004 or the two months ended December 31, 2003.

NOTE 29 — Summarized Financial Information for Subsidiaries with Debt Securities

PGS Geophysical AS, a Norwegian corporation, is a wholly owned subsidiary of the Company. PGS Geophysical AS is the largest geophysical services company within the PGS group of companies. PGS Geophysical AS is also the lessee of the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. PGS ASA (parent company) has fully and unconditionally guaranteed PGS Geophysical AS charter obligations in connection with certain debt securities issued in order to finance the purchase of these vessels. Summarized financial information for PGS Geophysical AS and its consolidated subsidiaries is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with U.S. GAAP. Separate financial statements and other disclosures with respect to PGS Geophysical AS are omitted because the information contained therein, in light of the information contained in the consolidated financial statements of the Company, would not be material.

The PGS Geophysical AS summarized financial information consists of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,		Two Months Ended December 31,	Ten Months Ended October 31,
	2005	2004	2003	2003
	(In thousands of dollars)			
Income Statement Data:				
Revenue	$332,190	$257,609	$ 17,610	$244,605
Operating profit (loss)	18,423	(4,761)	(26,009)	(4,238)
Net income (loss)	6,376	(22,868)	(12,671)	(6,752)
Balance Sheet Data:				
Current assets	$ 90,433	$116,910	$ 99,453	
Non-current assets	185,535	190,874	148,951	
Current liabilities	96,168	56,573	84,523	
Non-current liabilities	142,686	327,199	408,479	
Equity (deficit)	37,114	(75,988)	(244,598)	

Both Oslo Explorer PLC ("Explorer") and Oslo Challenger PLC ("Challenger"), Isle of Man public limited companies, are wholly owned subsidiaries of the Company, purchased in April 1997. Explorer and Challenger own the *Ramform Explorer* and the *Ramform Challenger*, respectively, and lease these vessels to PGS Geophysical AS pursuant to long-term bareboat charters. *Explorer* and *Challenger* are jointly and severally liable under the 8.28% First Preferred Mortgage Notes (see Note 16), in an original principal amount of $165.7 million, which were issued to finance the purchase of the *Ramform Explorer* and the *Ramform Challenger*. Summarized financial information for each of *Explorer* and *Challenger* is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with U.S. GAAP. Separate financial statements and other disclosures with respect to Explorer and Challenger are omitted because the information, in light of the information contained in the consolidated financial statements of the Company, would not be material.

The Oslo Explorer PLC and Oslo Challenger PLC summarized financial information consists of the following:

	Successor Company						Predecessor Company	
	Years Ended December 31,				Two Months Ended December 31, 2003		Ten Months Ended October 31, 2003	
	2005		2004					
	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger
	(In thousands of dollars)							
Income Statement Data:								
Revenue	$ 5,064	$ 5,455	$ 5,491	$ 5,858	$ 1,164	$ 1,169	$5,820	$5,844
Operating profit	4,883	5,273	5,346	5,713	(6,732)	(4,562)	5,693	5,717
Net income (loss)	766	1,157	799	1,166	(7,557)	(5,387)	1,566	1,590
Balance Sheet Data:								
Current assets	$ —	$ —	$ —	$ —	$ —	$ —		
Non-current assets	51,375	54,101	56,866	59,200	61,192	63,158		
Current liabilities	6,280	6,280	6,611	6,611	6,252	6,251		
Non-current liabilities	38,211	38,213	44,137	44,138	49,621	49,622		
Equity	6,884	9,608	6,118	8,451	5,319	7,285		

NOTE 30 — Supplemental Information — Oil and Gas Reserves and Costs (Unaudited)

In March 2005, the Company sold its oil and natural gas subsidiary Pertra AS to Talisman Energy (UK) Ltd. (see Note 24). Pertra did not meet the significant activities requirements for the year ended December 31, 2005. The Company meets the significant activities requirements for the year ended December 31, 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003. However, it is not considered material to the disclosure to separately present the changes in reserves or the changes in Standardized Measure for the Predecessor and Successor periods during the years ended December 31, 2004 and 2003.

Pertra had proved oil reserves associated with its 70% interest in PL 038 on the NCS. The Company, through its Marine Geophysical segment, also owns some small overriding royalty interests in oil and natural gas production offshore in the US Gulf of Mexico. The supplemental financial and oil and natural gas reserve information and standardized measure of future cash flows from proved reserves are presented for Pertra only. The overriding royalties financial results and oil and natural reserves are not considered material for disclosure. In addition, Pertra employed a Company FPSO to produce oil from PL 038. The revenues and expenses from this FPSO are eliminated in consolidation, but the expenses are presented gross for this supplemental presentation. As a result, the oil and natural gas results in this supplemental disclosure will not match the results in the consolidated statements of operations.

Financial Results Related to Oil and Natural Gas Activities.

The Successor results of operations, capitalized costs and costs incurred are based on the successful efforts method of accounting for oil and natural gas activities. The Predecessor results of operations and costs incurred are based on the SEC full cost method. See Note 2 for the description of each method. These methods may create significant differences in results, primarily because of differences in the capitalization policies under each method. As a result, the Successor and Predecessor results of operations, capitalized costs and costs incurred information are not comparable.

Results of operations relating to oil and natural gas producing activities are as follows:

	Successor Company		Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)		
Oil revenues (Revenues products)	$184,134	$ 9,544	$112,097
Production costs	93,036	6,354	62,296
Other operating costs	3,952	599	2,126
Accretion of asset retirement obligation	1,664	271	1,821
Exploration costs	20,062	4,344	—
Depletion, depreciation and amortization	38,965	743	30,826
Results of operations before tax	26,455	(2,767)	15,028
Income tax expense (benefit)	20,635	(2,159)	11,722
Results of operations	$ 5,820	$ (609)	$ 3,306

The above table does not include any amounts for allocated selling, general and administrative expense or finance income or expense.

Capitalized costs relating to oil and natural gas producing activities are set forth below:

	December 31, 2004
	(In thousands of dollars)
Capitalized Costs:	
Proved properties	$106,604
Unproved properties	4,000
Accumulated depreciation, depletion and amortization	(39,664)
Net	$ 70,940

As a supplemental disclosure, under the full cost method the depletion, depreciation and amortization rate for the Predecessor for the ten months ended October 31, 2003 was $8.65 per barrel of oil produced.

Following is a summary of costs incurred in oil and natural gas exploration and development activities:

	Successor Company		Predecessor Company
	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
	(In thousands of dollars)		
Exploration costs	$20,062	$13,262	$16,253
Development costs	76,342	4,375	10,318
Total costs incurred	$96,404	$17,637	$26,571

Proved Reserves and Standardized Measure.

The estimates of proved oil and natural gas reserves for Pertra as of December 31, 2004 was prepared by the Company's engineers in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The estimates were reviewed by an independent reservoir engineering consultant. All of Pertra's proved reserves are located in the Norwegian North Sea. The reserve estimates as of December 31, 2004 utilize oil prices of $40.24 per barrel (reflecting adjustments for oil quality). The Company's actual average sale price for oil produced in 2004 was $35.11 per barrel, compared to $29.37 per barrel in 2003.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. Reserve estimates are inherently imprecise, and estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The oil and natural gas proved reserve quantities and changes in reserve quantities, the Standardized Measure of Future Net Cash Flows from Proved Reserves (Standardized Measure) and the changes in Standardized Measure are presented for the years ended December 31, 2004 and 2003 and as of December 31, 2004, respectively. A company is required to disclose this information when it has significant oil and natural gas exploration and production activities.

The following tables provide a roll-forward of total proved reserves for the years ended December 31, 2004 and 2003, as well as proved developed reserves at year end, as of the beginning and end of each respective year, the Standardized Measure as of December 31, 2004 and 2003 and the changes in Standardized Measure for the years ended December 31, 2004 and 2003:

Estimated Quantities of Reserves (Unaudited)

	December 31, 2004
	(In thousands of dollars)
Crude Oil:	
Proved Reserves:	
Beginning of the year	7,818
Extensions and discoveries	2,976
Revisions of previous estimates	—
Production	(5,317)
End of year	5,477
Proved Developed Reserves:	
Beginning of year	2,114
End of year	5,477

Standardized Measure of Future Net Cash Flows from Proved Reserves (Unaudited)

	December 31, 2004
	(In thousands of dollars)
Future cash inflows	$220,440
Future production costs	108,253
Future development costs	—
Future abandonment costs	47,391
Future income taxes	51,762
Future net cash flows	13,034
Discount at 10% per annum	(2,288)
Standardized Measure	$ 15,322

Changes in Standardized Measure (Unaudited)

	December 31, 2004
	(In thousands of dollars)
Standardized Measure at beginning of year	$ 15,731
Revisions of reserves proved in prior years	—
Changes in prices and production costs	10,636
Changes in estimates of future development and abandonment costs	(4,847)
Net change in income taxes	1,757
Accretion of discount	1,573
Other, primarily timing of production	10,454
Extensions, discoveries and other additions, net of future production and development cost	58,216
Sales of oil and natural gas produced, net of production costs	(91,098)
Previously estimated development and abandonment costs incurred during the period	12,900
Net changes in Standardized Measure	(409)
Standardized Measure at end of year	$ 15,322

CERTIFICATIONS

I, Svein Rennemo, certify that:

1. I have reviewed this annual report on Form 20-F of Petroleum Geo-Services ASA;

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

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

4. The company's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the company and have:

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

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

(c) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

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

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

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

By: /s/ *Svein Rennemo*

Svein Rennemo
President and Chief Executive Officer

Date: April 5, 2006

CERTIFICATIONS

I, Gottfred Langseth, certify that:

1. I have reviewed this annual report on Form 20-F of Petroleum Geo-Services ASA;

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

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

4. The company's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the company and have:

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

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

(c) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

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

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

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

By: /s/ *Gottfred Langseth*

Gottfred Langseth
Senior Vice President and Chief Financial Officer

Date: April 5, 2006