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, 2003

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from to

Commission File Number: 1-14614

Petroleum Geo-Services ASA

(Exact name of registrant as specified in its charter)

Kingdom of Norway
(Jurisdiction of incorporation or organization)

Strandveien 4, N-1366 Lysaker, Norway
(Address of principal executive offices)

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

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

American Depositary Shares, each representing one ordinary share of nominal value NOK 30 per share

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: 20,000,000 ordinary shares, nominal value NOK 30 per share.

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 which financial statement the registrant has elected to follow.

Item 17 ☐ Item 18 ☑

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 ☐

PETROLEUM GEO-SERVICES ASA

ANNUAL REPORT ON FORM 20-F FOR THE YEAR ENDED DECEMBER 31, 2003

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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 "we" or "us" or "our," unless the context clearly indicates otherwise. As discussed more fully elsewhere in this annual report,

- during the second half of 2002, we experienced a substantial makeover of our senior management and appointed a new non-executive chairman of the board, a new chief executive officer and a new interim chief financial officer, who was replaced in January 2004 with a permanent chief financial officer;
- during 2003 we effected a financial restructuring of our parent holding company through a reorganization under Chapter 11 of the U.S. Bankruptcy Code in which we reduced our outstanding indebtedness by approximately $1,283 million; and
- upon our emergence from Chapter 11 proceedings in November 2003, a new board of directors took office.

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 herewith, 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.*

RESTATEMENT OF HISTORICAL FINANCIAL STATEMENTS

In November 2004, our current independent auditor, Ernst & Young AS, completed a re-audit of our 2001 financial statements under United States generally accepted accounting principles ("U.S. GAAP"). This re-audit resulted in a cumulative net reduction of our previously reported shareholders' equity as of January 1, 2001 of $204.3 million and a reduction in our previously reported net income (loss) for the year ended December 31, 2001 of $176.9 million. For a further discussion of the impact of the restatement on our selected financial information, please read "Operating and Financial Review and Prospects — Restatement of Previously Issued Audited Financial Statements" in Item 5 of this annual report. For a detailed discussion of the factors leading to the restatement and the financial impact of the restatement, please read note 4 of the notes to our consolidated financial statements in Item 18 of this annual report.

FORWARD-LOOKING INFORMATION

Some of the statements contained in this annual report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. They include such matters as:

- market conditions, competitive factors, expansion, technological developments and other trends in the businesses in which we operate;
- business strategies;
- maintaining and obtaining contracts for our floating production, storage and offloading vessels and the estimated productive lives of the fields served by such vessels;

- utilization of our seismic vessels and equipment;
- acquisition of contract and multi-client seismic data and expected future sales of seismic data;
- future capital expenditures and investments in our businesses;
- amortization charges for our multi-client library;
- estimates of quantities of our proved oil and natural gas reserves and the timing and amount of future production;
- statements about the expected drilling of wells and other planned activities relating to the development of our oil and natural gas properties;
- governmental and tax regulations and enforcement;
- future exposure to currency devaluations or exchange rate fluctuations;
- interest rates; and
- availability of a public trading market for our securities.

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 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. GAAP, our selected consolidated financial data as of December 31, 2003, 2002 and 2001 and for the period from November 1, 2003 through December 31, 2003, the period from January 1, 2003 through October 31, 2003 and for the years ended December 31, 2002 and 2001. We have derived the financial data presented below for such periods and as of such dates from our consolidated financial statements included in Item 18 of this annual report. The financial data presented below excludes our Production Services subsidiary, Atlantis oil and natural gas subsidiary and PGS Tigress 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 subject to the jurisdiction of the U.S. Bankruptcy Court beginning on July 29, 2003, the date that we filed a petition for protection and a reorganization plan under Chapter 11 of the U.S. Bankruptcy Code, until November 5, 2003. Accordingly, 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.

The reorganization plan became effective and was substantially consummated on November 5, 2003, at which time we emerged from Chapter 11. Under the plan, our then-existing bank debt and outstanding senior notes were canceled 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 — 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 adopted fresh-start reporting upon our emergence from Chapter 11 reorganization in accordance with 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 November 1, 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 at November 1, 2003. The carrying values of our liabilities were adjusted to their present values at October 31, 2003. 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.

The financial data presented below and in our consolidated financial statements and related notes included in Item 18 of this annual report as of and for the year ended December 31, 2001 have been restated, as described in note 4 to our consolidated financial statements included in Item 18 of this annual report and in "Operating and Financial Review and Prospects — Restatement of Previously Issued Audited Financial Statements" in Item 5 of this annual report. The financial data presented below and in our consolidated financial statements and related notes included in Item 18 of this annual report differs in many respects from that which had previously been reported as unaudited in the various earnings releases covering the periods since December 31, 2000. In addition, in light of the restatements reflected in the financial data presented below and in our consolidated financial statements and related notes included in Item 18 of this annual report as of and for all periods since January 1, 2001, you should not rely on financial statements that we previously reported for periods prior to January 1, 2001.

Pursuant to Item 3.A.1 of Form 20-F, selected financial data as of December 31, 2000 and 1999 and for each of the years in the two-year period ended December 31, 2000 have been omitted because such information cannot be provided on an audited or unaudited restated basis without unreasonable effort or expense. We believe that providing such information would involve unreasonable effort or expense because (1) the benefits of providing such information are diminished by the fact that we adopted fresh start reporting for financial statement purposes, effective November 1, 2003, as described above, (2) the preparation of such restated consolidated financial statements would be extremely time consuming and burdensome since our current independent auditors, Ernst & Young AS, were not our independent auditors during that two-year period, and (3) we identified significant adjustments to the beginning balances as of January 1, 2001 that would be burdensome and expensive to allocate and to apply consistently and with reasonable precision to the individual years 2000 and 1999.

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	2001 (Restated)
	(In thousands of dollars, except for share data)			
STATEMENT OF OPERATIONS DATA:				
Revenues	$ 172,371	$ 961,864	$ 1,043,231	$ 893,230
Operating profit (loss)	10,702	9,825	(488,609)	46,798
Reorganization items:				
Gain on debt discharge	—	1,253,851	—	—
Fresh-start adoption	—	(532,268)	—	—
Cost of reorganization	(3,325)	(52,334)	(3,616)	—
Income (loss) from continuing operations before cumulative effect of change in accounting principles	(9,818)	556,938	(809,903)	(140,125)
Net income (loss)	(9,953)	557,045	(1,174,678)	(172,479)
Basic and diluted income (loss) per share from continuing operations	$ (0.49)	$ 5.39	$ (7.84)	$ (1.36)
Basic and diluted net income (loss) per share	(0.50)	5.39	(11.37)	(1.68)
Basic and diluted weighted average shares outstanding	20,000,000	103,345,987	103,345,987	102,768,283
CASH FLOW DATA:				
Cash flows provided by operating activities	$ 58,346	$ 188,676	$ 293,007	$ 118,078
Cash flows (used in) investing activities	(25,089)	(69,732)	(274,497)	(220,516)
Cash flows provided by (used in) financing activities	(21,983)	(116,624)	(6,034)	56,852
Capital expenditures	15,985	42,065	56,735	147,536
Investment in multi-client library	9,461	81,142	151,590	174,028

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
BALANCE SHEET DATA:		
Total assets	$1,997,360	$2,839,757
Multi-client library, net	408,005	583,859
Total long-term debt and capital lease obligations	1,172,147	1,409,134
Guaranteed preferred beneficial interest in PGS junior subordinated debt securities	—	142,322
Common stock	85,714	71,089
Shareholders' equity (deficit)	353,634	(192,254)

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 have continuing issues regarding our internal controls.

Our independent auditors have identified the following material weaknesses:

- insufficient documentation of or adherence to accounting policies and procedures relating to significant financial statement accounts;
- inadequate U.S. GAAP expertise;
- inadequate quality of financial reporting and closing of the books process at the segment level;
- insufficient quality of support for accounting books and records; and
- insufficient supervision and review of control activities.

The Public Company Accounting Oversight Board has defined a material weakness as "a significant deficiency, or combination of significant deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim statements will not be prevented or detected." Accordingly, material weaknesses increase the risk that the financial information we report in the future could contain material errors. In November 2004, our independent auditors completed a re-audit of our 2001 financial statements under U.S. GAAP that resulted in restatements of our previously reported shareholders' equity as of January 1, 2001 and of our previously reported results of operations for the year ended December 31, 2001. While we believe that we have made substantial progress in addressing these material weaknesses as described in "Controls and Procedures" in Item 15 of this annual report, the material weaknesses have not been eliminated.

Despite the remedial steps we have taken, the existence of material weaknesses may also make it more difficult to comply with the new rules (including those under Section 404 of the Sarbanes-Oxley Act of 2002) on providing management reports on internal control over financial reporting. Unless we cure these material weaknesses, we will be unable to obtain an attestation report from our independent auditors, beginning with our annual report for 2005, as required by Sarbanes-Oxley Section 404.

The continuation of these financial reporting and internal control matters could have a negative impact on the market value of our securities.

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

As a result of the November 2003 consummation of our reorganization plan, we are operating our business under a new capital structure. In addition, 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 will not be 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

Although we have emerged from Chapter 11, we still have significant indebtedness.

We have a relatively high level of indebtedness in relation to our capital structure. Because of the level of our debt and other contractual obligations, a substantial portion of our cash flow from operations must be dedicated to debt service and payments of such obligations. To the extent we use cash flow for debt service and for payment of such obligations, such cash flow will not be available for capital investment or other purposes.

Our debt agreements may limit our flexibility in responding to changing market conditions or in pursuing business opportunities.

Our debt agreements contain provisions that restrict our ability, among other things, to:

- pay dividends or make other restricted payments;
- incur debt above specified amounts;
- create or permit to exist liens on our assets;
- consolidate, merge or transfer all or substantially all of our assets;
- sell assets for consideration other than cash or cash equivalents or without using the proceeds to reinvest in our businesses or to repay debt;
- undergo a change of control without having an obligation to purchase all of our senior notes;
- enter into certain transactions with affiliates; and
- engage in certain sale and leaseback transactions.

These restrictions may limit our flexibility in responding to changing market conditions or in pursuing business opportunities that we believe would have a positive effect on our business.

Potentially increased payments under vessel lease arrangements may adversely affect our financial condition, future results of operations and liquidity.

We have entered into vessel lease arrangements for five of our Ramform design seismic vessels, our FPSO vessel *Petrojarl Foinaven* and the topsides of our FPSO vessel *Ramform Banff*. The leases are all 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 lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. The UK Inland Revenue ("Inland Revenue") has not signed off on the lessors' claims to capital allowances related to our leases.

We understand that the Inland Revenue has generally deferred signing off on defeased leases (not just ours) pending the outcome of a case that has been appealed to the House of Lords, the highest UK court of appeal. We expect a decision from the House of Lords in late 2004. In that case, the Inland Revenue is challenging capital allowances associated with a defeased lease. While we believe that the lease transaction and the lease structure involved in this case are qualitatively different than those associated with our leases, if the House of Lords rules in favor of the Inland Revenue's position, there is a high likelihood that the Inland Revenue will also challenge other defeased leases.

If the Inland Revenue does successfully challenge one or more of our lease arrangements, we could be liable for increased rental payments to the lessors, additional collateral/security for such increased rental payments and increased termination sums that would apply on either a voluntary or default termination of our lease arrangements. The lessors might seek to impose such additional payments prior to a final resolution of any challenge of our leases by the Inland Revenue, with any increased collateral/security and/or rental payments released or rebated to us in the event that the challenge ultimately proves unsuccessful.

In the case noted above, while the Inland Revenue has challenged the capital allowances, it has not proposed the manner in which the associated lease should be treated and various alternative treatments exist. As a result, we cannot give you any assurances about the manner in which our leases may be treated or the amount of any additional liability we might incur if the Inland Revenue is successful in challenging one or more of our leases. However, the exposure could be very large.

If we become liable for a substantial amount at some point in the future, we may not have sources of liquidity that would be sufficient to permit us to pay the entire amount of such a possible liability. As a result, we could be required to seek additional sources of financing and possibly take other measures such as reducing or delaying capital expenditures and/or selling assets. We may not be able to take all of the actions necessary to meet these potential additional obligations on satisfactory terms or at all. As a result, if our leases were successfully challenged, it would likely have a material adverse affect on our financial condition, future results of operations and liquidity. Please read "Financial Information — Legal Proceedings — UK Legal Proceedings Involving Third Parties" in Item 8, "Operating and Financial Review and Prospects — Liquidity and Capital Resources — UK Leases" in Item 5 and notes 2 and 19 of the notes to our consolidated financial statements in Item 18 of this annual report for additional information relating to these UK lease matters.

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

As of October 31, 2004, our long-term unsecured indebtedness was not rated by a national credit rating agency. As long as we have no published credit rating, or if we were to have a relatively low, non-investment grade credit rating, our ability to access the debt capital markets could be restricted and our cost of raising capital would likely be increased. Such situation could restrict our ability to obtain additional financing or to refinance our existing indebtedness, or to do so on satisfactory terms.

The continued existence of material weaknesses as described above under "Risk Factors — Risk Factors Relating to Financial Reporting Matters — We have continuing issues regarding our internal controls" could similarly result in restrictions on our ability to obtain financing, or to do so on satisfactory terms.

In addition, the continued existence of the uncertainty relating to our UK leases as described above under "— Potentially increased payments under vessel lease arrangements may adversely affect our financial condition, future results of operations and liquidity" could restrict our ability to obtain additional financing, or to do so on satisfactory terms.

Risk Factors Relating to Our Business Operations Generally

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 trends in the prices of oil and natural gas, which have fluctuated widely in recent years. Lower oil and natural gas prices, actual or projected, may reduce the level of that spending, 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, in processing, seismic and other equipment and in acquiring and developing oil and natural gas reserves. We also incur relatively high fixed costs in our operations. 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:

- levels of activity planned by our customers;
- the timing of offshore lease sales 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;
- fluctuating oil and natural gas prices, which impact both customer demand for our geophysical and offshore production services and the revenues we receive in our production services business and from selling oil and natural gas in our oil and natural gas business;
- 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 frequently 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 (including 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 and embargoes. Our operations are also subject to various risks related to government activities, including:

- 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 disruption of operations from labor and political disturbances;
- 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, production services and oil and natural gas production businesses.

Our seismic data acquisition, offshore production services and oil and natural gas production activities 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 factors may curtail, delay or cancel our oil and natural gas development and production activities, including pressure or irregularities in geological formations, shortages of or delays in obtaining equipment and qualified personnel, equipment failures or accidents, adverse weather conditions, reductions in oil and natural gas prices, and limitations in the market for oil and natural gas.

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 exclusions for losses due to war risks and terrorists acts. 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 business interruptions.

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. Although we periodically undertake limited hedging activities in an attempt to reduce certain 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, our ability to enter into currency hedging transactions may be limited because of our lack of, or by our having a low, 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 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.

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 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. 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 if any material adverse change occurred in the general prospects for oil and natural gas exploration, development and production activities in the areas where we acquire multi-client data.

In particular, we own a significant amount of multi-client data offshore Brazil. As of December 31, 2003, the carrying value of our multi-client data offshore Brazil was $164.9 million. A slowdown in sales in this region could have an adverse impact on our multi-client data sales. If any of these risks occurs, the value of our multi-client data could be impaired and we would be required to recognize impairment charges. In the past, we have incurred substantial impairment charges related to our multi-client data.

Our future multi-client data sales are uncertain and depend on a variety of factors, many of which are beyond our control. In addition, the timing of these sales can vary greatly from period to period. Technological or regulatory changes or other developments also could reduce the value of 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 substantial 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 operating conditions (including weather, fishing activity, interference from other seismic vessels and other operating disturbances) 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.

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;
- 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 Primarily to Our Oil and Natural Gas Production Activities

Developing and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our results of operations.

Our oil and natural gas development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to acquire, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

The oil and natural gas business involves many uncertainties and operating risks that can cause substantial losses.

Our oil and natural gas operations involve a variety of operating risks, including:

- equipment failures and accidents;
- blow-outs and surface cratering and fires and explosions;
- natural disasters;

- abnormally pressured formations; and
- environmental hazards, such as uncontrollable flows of oil, natural gas, well fluids, toxic gases or other pollutants into the environment.

If we experience any of these problems, it could affect well bores and production facilities, which could adversely affect our ability to conduct our oil and natural gas operations. We could incur substantial liabilities and losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- suspension of our oil and natural gas operations; and
- repairs to resume operations.

Estimates of our oil and natural gas reserves, future cash flows and abandonment costs depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in these estimates or underlying assumptions will materially affect the quantities and present value of our reserves and could materially affect our results of operations.

Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and natural gas that cannot be directly measured. Reserve estimation is complex and inherently imprecise and requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Although we employ independent engineers to review our estimates of reserves, any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare our reserve estimates, we must estimate, project or assume, among other things:

- the quantities of oil and natural gas that may be ultimately produced;
- the timing of the production;
- the revenues associated with and the prices received for the proved reserves that are produced;
- the production and operating costs incurred; and
- the amount and timing of future development expenditures.

Actual future production, the timing of such production, oil and natural gas prices received for our production, production and operating costs we incur and the amount and timing of our development expenditures most likely will vary from our estimates. We will likely adjust estimates of our proved reserves from time to time to reflect production history, results of development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

If costs of abandonment for our oil and natural gas reservoirs and production equipment are materially greater than our estimates, they could have an adverse effect on results of operations.

A substantial or extended decline in oil and natural gas prices may adversely affect our oil and natural gas business and results of operations.

The price we receive for our oil and natural gas production heavily influences our revenue for our oil and natural gas segment. The prices we receive for our production depend on numerous factors that are beyond our control. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically.

We may not be able to find, develop or acquire properties to maintain or increase our levels of proved reserves.

Our future oil and natural gas production is highly dependent upon our level of success in finding, developing and acquiring reserves that are economically recoverable. As our reserves decline from production, we must incur significant capital expenditures if we desire to maintain production levels. We may not be able to identify, develop or complete the acquisition of properties with sufficient proved reserves to maintain or increase our reserve levels. In addition, substantially all of our proved reserves are located on the Norwegian Continental Shelf, a maturing resource province. If our development efforts in the NCS are unsuccessful, our proved reserves will decline unless we acquire additional properties. The availability of properties for acquisition depends largely on the divesting practices of oil and natural gas companies, commodity prices, general economic conditions and other factors that we cannot control. A substantial decrease in the availability of proved oil and natural gas properties in the NCS and elsewhere, or a substantial increase in the cost to acquire properties in the NCS and elsewhere, could adversely affect our ability to replace our reserves. A substantial increase in our lifting cost may adversely affect our oil and natural gas business and results of operations.

Substantially all of our oil and natural gas production is derived from assets that are concentrated in a geographic area under one production license.

Currently, substantially all of our production is derived from activities carried out by our subsidiary, Pertra, on the NCS under a license from the Norwegian Ministry of Petroleum and Energy. If oil and natural gas operations in that area were adversely affected in any way, our production levels could be materially and adversely impacted. In addition, if our license were to be terminated for any reason, our revenue and cash flow from our oil and natural gas operations would be adversely affected.

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 an issue pending with the Norwegian Central Tax Office (''CTO'') for 2002 relating to two of our subsidiaries that withdrew from the Norwegian tonnage tax regime. If the CTO position is upheld, we estimate that taxes payable for 2002, without considering mitigating actions, could increase by up to $24 million.

In addition, we have exposure relating to taxes as described above under ''Risk Factors Relating to Our Indebtedness and Other Obligations — Potentially increased payments under vessel lease arrangements may adversely affect our financial condition, future results of operations and liquidity.''

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.

Because our ADSs currently do not trade on a national exchange, you may have difficulty trading in our ADSs.

Our ADSs trade on the over-the-counter Pink Sheets under the symbol "PGEOY." Trades in our ADSs over-the-counter and through quotation on the Pink Sheets may not be executed as quickly as when the securities were listed on a national exchange. As a result, an investment in our ADSs may now be exposed to a greater risk of loss and limited liquidity. Although we are using reasonable commercial efforts to list our ADSs on a national exchange as soon as practicable, taking into account relevant United States listing requirements, we cannot provide assurance that we will be able to list our ADSs on a national securities exchange or that a market for our securities will develop and be maintained. Without a developed market, a holder of our securities may have difficulty disposing of them. Even if a market for PGS securities develops, we cannot provide any assurance about the degree of price volatility in any such market that does develop.

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-1366, telephone: +47-67-52-6400). 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 floating production, storage and offloading ("FPSO") units. We also own a small oil and natural gas company that produces oil and natural gas from a license on the Norwegian Continental Shelf ("NCS").

In February 2003, we revised our organizational structure. Prior to February 2003, we were organized and managed as two business segments, geophysical and production. Due to the increased size and importance of certain businesses within these segments and in order to improve our management structure, we now manage our overall business in four 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;
- *Production,* which owns and operates four harsh environment FPSO units in the North Sea; and
- *Pertra,* a small oil and natural gas company that owns 70% of and is the operator for Production License 038 on the NCS and also owns participating interests in two additional NCS licenses in areas that do not have current production.

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

Historical Development

The primary milestones in our historical development include the following:

- *January 1991:* Company is 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*
- *November 2001:* Announcement of business combination transaction with Veritas DGC (terminated in July 2002)
- *August 2002:* Acquisition of 70% ownership in and operatorship of Production License 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 interim Chief Financial Officer
- *December 2002:* Sale of Production Services subsidiary to Petrofac Ltd.
- *February 2003:* Sale of Atlantis subsidiary to Sinochem
- *June 2003:* Announcement of agreement in principle for proposed financial restructuring
- *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

2003 Developments

General Business Developments

Although 2003 was a period of financial difficulty and uncertainty, we believe that we took important steps to maintain and further develop our operating performance and to better position ourselves in the business segments in which we operate. Our primary business achievements in 2003 include:

- improving our cost structure through execution of our cost reduction program announced early in 2003;
- improving our position in the seismic contract market;
- extending the expected contract duration for three of our FPSO units as a result of field reserve upgrades and contract amendments;
- increasing our oil and natural gas reserves in Pertra resulting from a combination of acquisition and application of seismic data, reservoir modeling and an enhanced oil recovery drilling program;
- strong operating regularity and uptime in our businesses; and
- strong safety performance.

Financial Restructuring

In the late 1990s, we, like other geophysical companies, invested significantly in increased seismic acquisition capacity to meet expected growth in oil and natural gas exploration and production activities. During this period, we also invested heavily in our multi-client library, in our FPSO vessel *Ramform Banff* and in our oil and natural gas subsidiary Atlantis. To finance these investments, we incurred substantial amounts of debt that required increasing amounts of our cash flow to be devoted to debt service. The expected growth in demand for our services did not materialize, however, and the cash flow generated by many of our investments proved to be significantly lower than expected.

In 2002, it became clear that a comprehensive financial restructuring was crucial to our long-term viability and to provide a sustainable capital structure going forward. In late 2002 we engaged financial advisors and began discussions with representatives of our banks and bondholders with a view to developing a comprehensive financial restructuring.

On June 18, 2003, we announced that we had reached an agreement in principle with a majority of our banks and bondholders, a significant holder of our trust preferred securities, and a group of our largest shareholders to undertake a financial restructuring of our total debt through a conversion of our existing bank and bond debt and trust preferred securities into new debt and a majority of our post-restructuring equity.

On July 29, 2003, in order to implement the proposed restructuring plan, we voluntarily filed a petition for protection under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York and submitted a plan of reorganization and a disclosure statement. The case was filed only for our parent company and did not involve any of our operating subsidiaries.

The reorganization plan became effective and was substantially consummated on November 5, 2003, at which time we emerged from Chapter 11 reorganization. Under the plan, our then-existing bank debt and outstanding senior notes were canceled in exchange for a combination of new senior notes, new ordinary shares and the right to receive cash. For additional information about our restructuring, please read "Operating and Financial Review and Prospects — Financial Restructuring" in Item 5 of this annual report and note 3 of the notes to our consolidated financial statements included in Item 18 of this annual report.

Sales of Production Services, Atlantis and Tigress Subsidiaries

In December 2002, we sold our Production Services (formerly Atlantic Power Group) subsidiary to Petrofac Ltd. for approximately $20.2 million in cash and the right to receive additional amounts of up to $15.0 million if various contingencies occur.

In February 2003, we sold our Atlantis oil and natural gas subsidiary to China National Chemicals Import and Export Corporation, or "Sinochem," 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.

In December 2003, we sold our non-strategic software subsidiary, PGS Tigress (UK) Ltd., for a deferred compensation payable in 2004 and 2007 of $1.8 million in the aggregate.

Our Business Priorities

Following our financial reorganization in 2003, our strategic business focuses have included:

- improving cash flow from our existing operations;
- achieving further improvements in safety, operating regularity and cost;
- realizing business synergies between our different operations;
- identifying and pursuing attractive industry restructuring opportunities; and
- strengthening internal controls, corporate governance and human resource capabilities.

Our Geophysical Services

Overview

Our geophysical services business constitutes one of the major global players 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^{SM} — 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 2003, we made a deliberate shift in the utilization of our data acquisition capacity from multi-client to the contract market such that a substantial majority of our capacity was used in the contract market.

We manage our geophysical services through two segments:

- *Marine Geophysical,* which consists of both streamer and seafloor 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.

During 2003, we:

- made significant reductions in marine seismic staff;
- reduced vessel downtime;
- increased our average productivity per vessel; and
- significantly reduced capital expenditures in Onshore.

Our Strategies for Geophysical Services

Our principal strategies for our geophysical services include:

- capitalizing on our strong cost position and operating performance;
- focusing on the contract market;
- investing in multi-client data in a financially disciplined manner that complements our contract data acquisition activities;
- increasing our focus on the less volatile reservoir and production related seismic market through application of our HD3D^{SM} techniques, 4D acquisition and multi-component acquisition; and
- identifying and pursuing attractive industry restructuring opportunities.

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

- our Ramform seismic vessels and deep water seafloor FOURcE^{SM} acquisition systems;
- 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 business include:

- 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 large surveys;
- high channel count for onshore operations; and
- our highly experienced work force.

Geographic Areas of Operation

We have divided our Marine Geophysical business in 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 in 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 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;
- West Africa;
- 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, often are turnkey contracts. Under this turnkey method, 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 business interruption, due to causes beyond our control such as, among others, weather and permitting.

During 2003, we increased our emphasis on acquiring seismic data on a contract basis. We performed contract operations during 2003 in the North Sea; offshore and onshore Mexico; offshore West Africa, Australia, China and other countries in the Asia Pacific region; offshore and onshore South America; offshore Canada; onshore in the U.S. mid-continent, Rocky Mountains, Gulf Coast and Alaskan North Slope regions and offshore and onshore in Central Asia and the Middle East.

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 is 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 prefunding for a portion of these costs reduces this risk. The level of prefunding we require before initiating a multi-client seismic survey is determined 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;
- 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. We continue to build and market our multi-client data library, including seafloor and onshore data, but we also intend to acquire multi-client data in additional geographic areas from time to time. During 2003, compared to earlier years, we substantially reduced the amount we invested in new multi-client data.

In our multi-client operations, we make initial sales of the data prior to project completion, which we refer to as prefunding 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, for successful concession award or sometimes 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, the actual 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. In prior years, we also marketed the data through various agreements with third parties, most of which have been terminated.

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 reorganized our data processing division during 2003 to be part of our regional marine business unit. Technical support, research and development and computer operations continue to be provided on a global basis. As of October 31, 2004, we operated nine land-based seismic data processing centers, with the largest centers being located in Houston, Texas, U.S.; London, England; Lysaker, Norway; Cairo, Egypt; and Perth, Australia. The largest seismic processing centers utilize computer resources organized in a global computer resource organization consisting of three major computer centers located in Houston, London and Perth. These three centers are inter-connected through high capacity network links. In addition, some of our marine seismic crews have the capability to perform data processing.

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;
- 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 October 31, 2004, we had a total of ten 3D marine seismic streamer crews operating ten seismic vessels, and we had one seafloor seismic crew operating a total of three vessels.

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. As of October 31, 2004, we operated one seafloor seismic crew consisting of one recording vessel, one source vessel and one cable laying vessel.

In our multi-component seafloor seismic operations, we record both hydrophone and geophone data simultaneously. Processing the data with PGS' proprietary software allows for enhanced reservoir imaging and characterization, which improves chances of discovery success at the exploration stage, information relating to the size of and reserve estimates for reservoirs at the appraisal and development stages, decision-making regarding production strategy and the chances of maximizing total reserve recovery at the production stage.

Vessel Fleet and Crews. We acquire marine seismic data using seismic crews on both 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 airgun array firing system that activates the acoustic energy source.

For the seafloor seismic operations, the *Ocean Explorer* and the *Bergen Surveyor* each has a dynamic positioning system and recording instrumentation that permits the recording of data from up to 48 kilometers of ocean bottom cables. These vessels also have equipment to deploy and recover cables automatically.

We provide in the following table information as of October 31, 2004 about our marine seismic data acquisition vessels.

Vessel Name	Year rigged/ converted	Total length (feet)	Total beam (feet)	Long-length streamer capability	Maximum streamers deployed (through December 31, 2003)	Owned or charter expiration
3D Seismic Vessels:						
Ramform Explorer	1995	270	130	12	8	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	10	2023(1)
Ramform Victory	1999	284	130	20	16	2024(1)
Ramform Vanguard	1999	284	130	20	10	2024(1)
Atlantic Explorer	1994	300	58	6	6	Owned
American Explorer	1994	306	59	8	8	Owned
Nordic Explorer	1993	209	54	6	6	Owned
Orient Explorer	1995/96	246	49	4	4	2004
Seafloor Seismic Vessels:						
Falcon Explorer	1997	266	53	N/A	N/A	2005
Bergen Surveyor	1997	217	48	N/A	N/A	2005(2)
Ocean Explorer	1993/95	269	59	N/A	N/A	Owned

(1) We have UK lease arrangements for each of the *Ramform Valiant*, the *Ramform Viking*, the *Ramform Victory* and the *Ramform Vanguard* and a conditional sale and leaseback arrangement with respect to 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 19 of the notes to our consolidated financial statements included in Item 18 of this annual report.

(2) We can terminate the charter for this vessel on three months' notice.

Competition in Our Geophysical Businesses. 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, crew 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 all our seismic acquisition operations on land and in very shallow water and transition zones, including the 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 2003, we conducted seismic acquisition operations in the United States (Gulf Coast, mid-continent, Rocky Mountains and Alaska), Mexico, Ecuador, Saudi Arabia and Bangladesh. During 2004, active crew counts have ranged from four to eight, operating in various areas including Mexico, the United States, Bangladesh, Ecuador and Bolivia. As of October 31, 2004, we had five crews conducting activities in Mexico, the United States and Canada. We also have environmental specific operating equipment in Alaska and in the Middle East. We are pursuing additional contract opportunities in Mexico, South America, Africa, Central Asia, the United States and the Middle East and are expanding our multi-client onshore library in the U.S. mid-continent.

In the market for onshore seismic services, we are a medium sized operator among a large number of regional and global competitors. Competition in the Onshore segment is intense and varies from region to region. In particular, we have seen increased competition from Chinese operators who have aggressively expanded their global presence. 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

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. During 2003, we improved or extended three of our FPSO contracts as follows:

- *Petrojarl Varg* contract expected to extend beyond 2006 based on additional reserves and expected future development;
- *Petrojarl I* contract estimated to extend until 2007 based on additional reserves; and
- *Ramform Banff* contract amended with improved economic terms.

An FPSO system is a ship-based type of mobile production unit that produces, processes, stores and offloads oil and processes, reinjects 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:

- 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:

- capitalizing on our strong North Sea floating production operations;
- maximizing the value of our existing contracts through maintaining a high level of operational performance, through incentive structures and through pursuing opportunities to extend the contracts;
- capturing the potential upside from reservoir exposure utilizing in-house competence; and
- pursuing growth opportunities through offering solutions for new developments.

We believe a number of redeployment opportunities exist in the North Sea, particularly on the Norwegian Continental Shelf, where we currently operate two vessels. We also intend to continue to evaluate opportunities in other regions.

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 and/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 October 31, 2004 about our four FPSO vessels. In addition to these four vessels, as of October 31, 2004 we used two FPSO shuttle tankers and one storage tanker from third-party contractors under operating leases (some of which are in turn subleased) expiring at various dates from 2004 through 2013. In addition, as of October 31, 2004 we owned a 40% interest in a French company that owns the FPSO Ikdam, which is producing the Isis field located offshore Tunisia. As of that date, production from the vessel was approximately 8,000 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/equipment under long-term charters that give us the option to purchase the vessel/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 19 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. At that time, we began receiving a fixed day rate designed to cover operating expenses and a fixed tariff per barrel of stabilized crude oil produced. Due to the combination of a volume-dependent tariff structure, underperformance of the reservoir and higher than expected costs of operating the field, we incurred substantial losses on the original contract. In addition, for parts of years 2000 and 2001 we placed the vessel in the shipyard for necessary modifications and improvements.

In December 2003, we reached an agreement with the field operator to substantially amend our Banff field contract. Under the amended contract, effective January 1, 2004, we will continue to produce the Banff field with the *Ramform Banff* until the end of the life of the field. 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 per day, with a minimum total rate of $125,000 per day. These rates are applicable for production through 2014. 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 subsea 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 subsea facilities at our cost and, upon completion of our obligations under the contract, the operator will owe us five million British pounds.

In October 2004, one well from the nearby Kyle field commenced production through the *Ramform Banff*.

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 the most recent filed estimates by the operator, we now expect production under the contract to continue until at least 2007.

The contract provides for compensation consisting of a tariff-based element of $3.50 per barrel and a fixed day rate of $17,750, 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 455,088 (approximately $70,000) 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. In the event of cancellation taking effect before November 2006, the contract provides that cancellation of the contract by Britoil will trigger a cancellation fee, payable by Britoil, of $24 million. This cancellation fee reduces thereafter, so that no cancellation fee is payable after November 2007. Britoil may also terminate the contract without paying a cancellation fee 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 $70,000 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 $0.70 per barrel of oil produced per day from East Foinaven. The contract provides for guaranteed minimum production amounts of 51,000 barrels per day for the twelve month period that ended in November 2003, 35,500 barrels per day for the twelve month period ending November 2004 and 24,000 barrels per day for the twelve month period ending November 2005.

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 some breaches of contract; and
- pay for pollution damage caused by diesel or lubricants.

Petrojarl Varg

The *Petrojarl Varg* operates on the Varg field on the Norwegian Continental Shelf of the North Sea under a contract with the license owners of Production License ("PL") 038, where production began in December 1998. Our Pertra subsidiary has a 70% interest in PL 038, which includes the Varg field. The remaining 30% is held by Petoro, manager of the Norwegian State's Direct Financial Interests.

Because of recent extensions to the life of the Varg field, we entered into an amendment, effective from May 29, 2004, to the charter and operating agreements with the PL 038 license owners governing production of the field. Under the amended agreements, our compensation consists of a fixed base day rate of $90,000 and tariff of $6.30 per barrel produced per day. Prior to May 29, 2004, our compensation consisted of a tariff of $11.12 per barrel produced per day. The charter and operating agreements 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.

As a result of the reduced production from the Varg field announced on November 8, 2004, we expect that the *Petrojarl Varg* will receive reduced revenues due to the tariff-based component of the compensation arrangement relating to the vessel. For additional information relating to the damage that caused such reduced production, please see "— Oil and Natural Gas Production Segment (Pertra)" below.

Employee Lockout and Strike in September/October 2004

Effective September 2, 2004, the *Petrojarl I* was selected by the Norwegian Shipowners Association to be included in a general employee lockout affecting several NCS installations. Production from the *Petrojarl I* was shut down from September 3 through October 27, 2004. For approximately two weeks in October 2004, production on the *Petrojarl Varg* was shut down as a result of a labor conflict involving a number of service providers in the NCS. These labor conflicts ended on October 27, 2004 after intervention by Norwegian authorities. Because of *force majeure* and other payments we expect to receive for operations during these periods, these labor matters are not expected to have a material adverse effect on our operations.

Competition in Our Production Operations

Our production operations generally compete with other FPSO operators, with fixed installations and tension leg platforms, with subsea 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)

In January 2002, we established a new, wholly owned subsidiary, Pertra AS ("Pertra"), to secure continued employment of the *Petrojarl Varg,* to pursue small field opportunities on the NCS and to act as a facilitator for FPSO opportunities. Pertra was formally approved in February 2002 as a license holder and operator on the NCS of the North Sea.

In August 2002, Pertra acquired a 70% interest in, and achieved operatorship of, the Varg field and PL 038. Our license for PL 038 is effective through April 1, 2011. PL 038 is located approximately 140 miles southwest of Stavanger in the South North Sea and includes the Varg oil field and the Varg South discovery.

When we acquired our 70% interest in the Varg field, we also assumed 70% of the abandonment liabilities associated with the fields on the license and any future environmental liabilities that may be generated by production from the fields on the license. We have no other commitments related to the license beyond these abandonment and environmental liabilities.

In addition to the Varg field, PL 038 comprises a number of prospects and the Varg South field. We have acquired 3D seismic data over some areas of the license in order to enhance our understanding of the geology and prospectivity of these areas and are evaluating several development options. Further reservoir studies were also performed in 2003 and 2004 to identify new drilling targets for production wells, both in the existing boundaries of the Varg field and additional fault blocks, including the Varg South field. In

2003 we drilled three wells, two of which were appraisal wells. In 2004, we have drilled four wells, one of which was a water injection well. Of the wells we drilled in 2003 and 2004, six were productive wells and one appraisal well was unproductive. We expect to drill three to four development wells and one to two exploration wells in 2005.

From October 13 to October 27, 2004, production on the Varg field was shut down as a result of a labor conflict involving a number of service providers on the NCS. On November 8, 2004, we announced that production from the Varg field had been reduced to approximately 15,000 barrels per day as a result of damage to the main production riser going from the wellhead platform to *Petrojarl Varg* that occurred on November 5, 2004. Production will continue at a lower rate until the main production riser is repaired.

In the 18th round licensing awards offshore Norway in June 2004, we were awarded an 80% participation and operatorship in one license (PL 321) and a 30% participation in a second license (PL 316). Our obligations under these licenses are as described under "— Other Factors Related to Our Business — Capital Expenditures" below.

Our strategy for Pertra includes:

- building on the success of the Varg field and the achievements in the 18th licensing round in Norway to create a strong NCS operator on small fields; and
- exploring strategic opportunities, including, among others, an evaluation of a potential broadening of Pertra's ownership base to facilitate and accelerate growth.

We also own relatively small overriding royalty interests in oil and natural gas production in the U.S. offshore Gulf of Mexico. We obtained these interests at various times in return for seismic acquisition services.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2003 and 2002. The December 31, 2003 reserve estimates were prepared by company engineers and were reviewed by an independent reservoir engineering consultant. The process of estimating natural gas and oil reserves is complex and inherently imprecise and requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Please read "Key Information — Risk Factors — Risk Factors Relating Primarily to Our Oil and Natural Gas Production Activities" in Item 3 of this annual report.

	December 31, 2003	December 31, 2002
Proved Crude Oil Reserves (mbbls):		
Developed	2,114	3,272
Undeveloped	5,704	865
	7,818	4,137

The increase of proved undeveloped reserves from December 31, 2002 to December 31, 2003 is primarily due to the drilling of two wells commenced in December 2003. Production from the wells commenced in January and March 2004, respectively.

The table includes proved reserves for Pertra only, which was established in January 2002. We have not included the proved reserves of our oil and natural gas subsidiary Atlantis, which we sold in February 2003. We are treating that subsidiary as discontinued operations for accounting purposes in this annual report. In addition, we own small overriding royalty interests in the U.S. Gulf of Mexico. The proved reserves associated with these overriding royalty interests totaled 90,000 barrels of oil and 264 million cubic feet of natural gas as of December 31, 2003.

By October 15 of each year, we report oil and natural gas reserves estimated as of the upcoming year end to the Norwegian government for inclusion in the Revised National Budget. These reserves include all categories (proved, probable and possible) and are not limited by economic cut-off. As a result, such reserves reported to the Norwegian government are not comparable to the proved reserves included in this annual report.

We had net oil production of 4,056 mbbls and 1,298 mbbls for the years ended December 31, 2003 and 2002, respectively. Please refer to other information regarding our oil and natural gas production in note 29 of the notes to our consolidated financial statements included in Item 18 of this annual report.

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 by customers to discover and produce oil and natural gas in demanding environments. 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.

In 2003, we combined our research and development activities for marine data acquisition and data processing into one technology organization. Our research and development activities carried out in 2003 include:

- successful development and testing of semi-solid streamers for our marine seismic fleet;
- the development of new technology enabling improved seafloor seismic operations in deep waters;
- testing of the first all-optical seafloor data acquisition cable offshore Norway;
- development and testing of passive acoustic monitoring methods for monitoring whales and other aquatic mammals during seismic acquisition; and
- significant improvement of our seismic processing package, the Cube ManagerSM.

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. We are seeking ISO environmental certification of all our FPSO units and associated shuttle tanker fleet. 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.

In 1994, we established our own captive re-insurance company to provide 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 noted below, this insurance is subject to deductibles and limits of coverage and is supplemented by commercial reinsurance arrangements.

We obtain a substantial portion of our casualty insurance through this wholly-owned captive re-insurance company. This company retains risk of $4.5 million for each accident, with a maximum annual risk retention of $9 million per year. Our various operating companies also retain levels of risk when obtaining this casualty insurance from the captive company, ranging from $150,000 per accident for our seismic vessels, up to $200,000 per accident for our streamers and $750,000 per accident for our FPSOs.

We carry insurance for our oil and natural gas operations covering physical loss or damage, with limits of $100 million for wellhead platforms, $5 million for risers, $20 million for pipelines (effective from October 1, 2004) and $100 million for control of well, including redrilling, seepage and pollution. We also carry for our oil and natural gas operations general third party liability insurance with a limit of $100 million covering personal injury and seepage, pollution and remediation if and when the seepage and pollution under control of well insurance has been exhausted.

Governmental Regulation

In various areas of the world, we are required to obtain and we have acquired 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 two years. 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 other areas, including Brazil and Brunei, the timing and extent of these licensing rounds tend to be 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.

Through our wholly owned subsidiary, Pertra AS, we hold a concession to explore for, produce and transport petroleum under the Norwegian regulatory framework until April 1, 2011. The Norwegian government has, and we comply with, financial standing requirements for the grant of a production license.

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 26 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

We incorporate by reference in response to this item the information regarding the geographic mix of our operations in note 26 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 October 31, 2004.

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%
PGS Reservoir AS	Norway	100%
Multiklient Invest AS	Norway	100%
Pertra AS	Norway	100%
Petroleum Geo-Services, Inc.	United States	100%
Petroleum Geo-Services (UK) Ltd.	United Kingdom	100%
Seahouse Insurance Ltd.	Bermuda	100%
PGS Mexicana SA de CV	Mexico	100%
PGS Rio Bonito SA	Brazil	99%
Dalmorneftegeofizika PGS AS	Norway	49%
Walther Herwig AS	Norway	100%
Geo Explorer AS	Norway	50%
Shanghai Tensor CNOOC Geophysical Ltd.	United Kingdom	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%
UNACO AB	Sweden	100%
Hara Skip AS	Norway	100%

Name	Jurisdiction	Ownership
PGS Exploration, SDNBHD	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 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 4 DA	Norway	99.25%
SOH, Inc.	United States	100%
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 Administracion y Servicios S.A. de C.V.	Mexico	100%
PGS Venezuela SA de CV	Venezuela	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, Australia, Brazil, China, Egypt, England, Mexico, Nigeria, Russia, Singapore, Scotland, the United Arab Emirates and Venezuela. We believe that all leased properties are well maintained and are suitable and adequate for our present activities.

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 Information" 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 FPSO units. We also own a small oil and natural gas company with offshore operations on the NCS.

In February 2003, we revised our organizational structure. Prior to February 2003, we were organized and managed as two business segments, geophysical and production. Due to the increased size and importance of certain businesses within these segments and in order to improve our management structure, we now manage our overall business in four 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;
- *Production,* which owns and operates four harsh environment FPSO units in the North Sea; and
- *Pertra,* a small oil and natural gas company that owns 70% of and is the operator for Production License ("PL") 038 on the NCS and also owns participating interests in two additional NCS licenses in areas that do not have current production.

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

We discuss our results of operations below based on these four business segments. For a more comprehensive discussion of our history and development, including our four business segments, key 2003 developments and our strategic focus, please read "Information on the Company" in Item 4 of this annual report.

Key Factors Impacting 2003 Results

You should consider the following unusual or significant items and the following events, developments and factors in considering our results for 2003. Each of these factors is discussed in greater detail further below in this Item 5.

- We completed a significant financial restructuring in 2003 that included a voluntary Chapter 11 bankruptcy filing on July 29, 2003, emergence from Chapter 11 on November 5, 2003, and implementation of "fresh-start" accounting beginning November 1, 2003, which includes adjusting the recorded value of our assets and liabilities to reflect fair value as of that date.
- In connection with our adoption of fresh start reporting as of November 1, 2003, we made various changes in our accounting policies relating to, among other things, (a) expensing certain expenditures that previously were capitalized, (b) adopting the successful efforts method of accounting for our oil and gas operations, (c) changing our amortization policy for our multi-client library, and (d) changing the depreciable lives of our vessels.

- The financial results for the ten month period ended October 31, 2003 included in this annual report include significant impairment charges related to our long lived assets.

- In February 2003, we sold our Atlantis oil and natural gas subsidiary for $48.6 million. The operating results for Atlantis for the 2003 period prior to sale are treated as discontinued operations in our financial statements.

- We discovered material errors in previously issued financial statements. The consolidated financial statements included in this annual report reflect restated results from 2001, including restated 2001 beginning balances. We have not allocated these adjustments to years prior to 2001. Some of these restatements have carry forward effects into our results for 2003.

- Our independent auditors have issued to us material weakness letters that identified several material weaknesses. While we believe we have made substantial progress in addressing these material weaknesses, they have not been eliminated. For additional information relating to these material weaknesses and the steps we have taken and are taking to remedy such weaknesses, please read "Controls and Procedures" in Item 15 of this annual report.

Financial Restructuring

In the late 1990s, we, like other geophysical companies, invested significantly in increased seismic acquisition capacity, in particular Marine Geophysical capacity, to meet expected growth in oil and natural gas exploration and production activities. During this period, we also invested heavily in our multi-client library, in our FPSO vessel *Ramform Banff* and in our oil and natural gas subsidiary Atlantis. To finance these investments, we incurred substantial amounts of debt that required increasing amounts of our cash flow to be devoted to debt service. The expected growth in demand for our services did not materialize, however, and the cash flow generated by many of our investments proved to be significantly lower than expected.

In 2002, it became clear that a comprehensive financial restructuring was crucial to our long-term viability and to provide a sustainable capital structure going forward. In late 2002 we engaged financial advisors and began discussions with representatives of our banks and bondholders with a view to developing a comprehensive financial restructuring.

On June 18, 2003, we announced that we had reached an agreement in principal with a majority of our banks and bondholders, a significant holder of our trust preferred securities, and a group of our largest shareholders to undertake a financial restructuring of our total debt through a conversion of our existing bank and bond debt and trust preferred securities into new debt and a majority of our post-restructuring equity.

On July 29, 2003, in order to implement the proposed restructuring plan, we voluntarily filed a petition for protection under Chapter 11 of the U.S. Bankruptcy Code with the U.S. Bankruptcy Court for the Southern District of New York and submitted a plan of reorganization and a disclosure statement. The case was filed only for our parent company and did not involve any of our operating subsidiaries.

The reorganization plan became effective and was substantially consummated on November 5, 2003, at which time we emerged from Chapter 11 reorganization. Pursuant to the reorganization plan, $2,140 million of our senior unsecured debt was cancelled, and the associated creditors received the following:

- $746 million of 10% senior unsecured notes due 2010;

- $250 million of 8% senior unsecured notes due 2006;

- $4.8 million of an eight-year unsecured senior term loan facility;

- 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.

In accordance with the reorganization plan, the existing share capital, consisting of 103,345,987 shares, par value NOK 5 per share, 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 (one new share per 129 old shares), as well as 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. In addition, owners of $144 million of trust preferred securities received 5%, or 1,000,000, of the new ordinary shares. The principal amount of our interest-bearing debt and capital lease obligations immediately after the restructuring was approximately $1,210 million, a reduction of approximately $1,283 million.

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 were required to adjust the recorded value of our assets and liabilities to reflect their fair market value as of the date we emerged from Chapter 11 reorganization, with any shortfalls or excesses in such values, as compared to our reorganization value, being reflected as goodwill or downward adjustments to long-lived assets, respectively. These estimates of fair value have been reflected in our consolidated balance sheet as of December 31, 2003.

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 are:

- Expenditures incurred in connection with steaming and mobilization will be 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.

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. Refer to note 3 for disclosure of the fresh-start adjustments.

Restatement of Previously Issued Audited Financial Statements

We have restated our previously reported consolidated financial statements for the year ended December 31, 2001. We have also restated our January 1, 2001 opening balance retained earnings for errors that relate to prior periods. Except as otherwise specified, all information presented in the accompanying consolidated financial statements and the related notes include all such restatements.

We present below the effects of the restatements on our January 1, 2001 opening retained earnings balance and our net income (loss) for the year ended December 31, 2001.

	Retained earnings as of January 1, 2001	Net income (loss) Year ended December 31, 2001
	(In thousands of dollars)	
As reported	$ 94,410	$ 4,453
Restatements:		
Revenue recognition	(25,297)	(2,697)
Multi-client library (cost capitalization, impairment and amortization)	(100,214)	(37,649)
FPSOs (cost capitalization, impairment and depreciation)	(59,981)	(63,674)
Asset retirement obligation for Banff field	(7,060)	(3,356)
Contract loss accruals	40,132	(31,532)
Lease accounting	(4,980)	(23,269)
Ceiling test for oil and natural gas assets	—	(20,817)
UK leases	(41,202)	1,163
Taxes	53,825	3,208
Other adjustments:		
Cost capitalization steaming, mobilization and yard stay	(8,173)	(11,493)
Accrued social security taxes	(6,371)	(1,688)
Errors consolidated subsidiary	(11,542)	3,351
Fair value of TES contracts	—	8,885
Settlement agreement with customer	(5,000)	5,000
Various	(28,410)	(2,364)
As restated	$(109,863)	$(172,479)

For additional information relating to the restatements, please read note 4 to the consolidated financial statements included in Item 18 of this annual report.

For information relating to material weaknesses in our internal controls over financial reporting, please read "Controls and Procedures" in Item 15 of this annual report.

Critical Accounting Policies and Estimates

Our discussion of operating results and financial condition is based on our consolidated financial statements, which are prepared in accordance with U.S. GAAP. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amount of assets and liabilities and 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 our evaluations. We believe that our estimates and assumptions are reasonable, but we acknowledge that actual results may vary. Our significant accounting policies are described in note 2 to the consolidated financial statements included in Item 18 of this annual report.

We believe the accounting policies listed and summarized in greater detail below are among the most critical in the preparation and evaluation of our financial statements and involve the use of assumptions and estimates that require a higher degree of judgment and complexity. As a result, these policies and the related assumptions and estimates could materially affect our reported assets, liabilities, revenues and expenses if the assumptions 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 relate to:

- revenue recognition;
- multi-client data library, including cost capitalization, sales and amortization;
- oil and natural gas transactions, including capitalization, amortization and impairment;
- long lived assets, particularly impairment and depreciation, depletion and amortization;
- deferred tax assets; and
- fresh start reporting.

Revenue Recognition

Our revenue recognition policy is based on the guidelines set forth in Staff Accounting Bulletin ("SAB") Nos. 101 and 104 of the U.S. Securities and Exchange Commission, which establishes rules for recognizing revenue for public companies. SAB No. 101 allows revenue to be recognized only when persuasive evidence of a sales arrangement exists, delivery has occurred or services have been rendered, the sales price is determinable and collection is reasonably assured.

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 these services to the customer. The geophysical services business is of a nature where costs from time to time are incurred and recognized prior to the time revenues can be recognized, and 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, tariff based revenues, based on barrels produced, are recognized as production occurs. Second, day rate revenues are recognized over the passage of time. Oil and natural gas production revenue is recognized when the production is delivered and ownership has passed to the customer.

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

- Late sales — we grant a license to the customer to a specified portion of the library.
- Volume sales agreements — we grant a license or licenses to a specified number of blocks within the library in a defined geographical area. These licenses typically enable the customer to 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 late sales revenue when the customer executes a valid license agreement and has been granted access to the library and collection is reasonably assured. We recognize revenue 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. We recognize revenue from pre-funding arrangements as the data is acquired, generally based on physical progress, on a proportionate performance basis.

Multi-Client Data Library

Revenue recognition relating to our multi-client library is discussed above under "— Revenue Recognition."

We capitalize as an asset the costs associated with the acquisition and processing of multi-client data. We base our amortization of the multi-client data library on the sales forecast method. Under this method, amortization of a survey's cost is based on the ratio between the cost of the survey and the total forecasted sales 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, which we will calculate annually at year end, is the total cost of each project less accumulated straight line minimum amortization. We periodically evaluate the projects in the multi-client library for impairment. Prior to our adoption of fresh start reporting, amortization was based on the ratio of actual sales to expected sales with a minimum amortization based on five to eight year lives.

In determining the ordinary amortization rates applied to and fair value of the surveys that constitute our multi-client data library, we consider expected future multi-client sales and market developments as well as 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 outside our 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.

Over the last three years, the sales expectations for our multi-client library have declined significantly, reflecting a weakening of the market for multi-client data. The main effect of this decline has been an increase in amortization rates over time and an impairment of the multi-client data library of $90 million for the Predecessor for the ten months ended October 31, 2003, $200.4 million for 2002 and $12.7 million for 2001.

Oil and Natural Gas Accounting

Following our adoption of fresh-start reporting, we use 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 to be non-productive, the drilling and equipment costs of the well are expensed 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.

The estimates of proved oil and natural gas reserves as of December 31, 2003 and 2002 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. 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. In addition, 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, we expect the estimates relating to our reserves to change as additional information becomes available in the future. Future changes in proved oil and gas reserves could have a material impact on unit-of-production rates for depreciation, depletion and amortization, as well as for impairment testing.

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 were 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 were 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.

Accounting for Long Lived Assets

Effective January 1, 2002, we adopted Statement of Financial Accounting Standards ("SFAS") No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," which provides guidance for evaluating the recoverability of all long-lived assets, principally property, plant and equipment and definite-lived intangible assets, including multi-client library. SFAS No. 144 provides similar guidance to SFAS No. 121, which was applied prior to January 1, 2002. SFAS No. 144 requires that long-lived assets (or the group of assets, including the asset in question, that represents the lowest level of separately identifiable cash flows) be evaluated whenever events or changes in circumstances indicate that the carrying amount of assets or cash generating units may not be recoverable. 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. Long-lived assets (multi-client data library, property and equipment, and proved oil and natural gas assets accounted for under the successful efforts method) are 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 (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. Unproved oil and gas properties are assessed for impairment in accordance with the guidelines of SFAS No. 19. Prior to the adoption of fresh-start reporting, oil and natural gas assets were assessed for impairment 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 regarding 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 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.

Deferred tax assets

We evaluated the need for valuation allowances for our deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. We have recorded valuation allowances for 100% of net deferred tax assets due to cumulative losses in recent years and management's expectations about the generation of taxable income from contracts that are currently in effect. Because of these cumulative losses and future expectations, we have concluded that it was more likely than not that the net deferred tax assets would not be realized and have recognized the valuation allowances accordingly. We believe that we have valid tax planning strategies and therefore may ultimately be successful in utilizing those net deferred tax assets. To the extent that we continue to generate deferred tax assets, we will continue to assess the need for valuation allowances on those assets.

If in the future benefits are attributed to pre-reorganization amounts, SOP 90-7 requires recognition through reduction of intangible assets until exhausted, and thereafter as a direct addition to paid-in capital. All significant parts of the valuation allowance of $368.5 million as of December 31, 2003 are related to pre-reorganization amounts and will only affect net income with the reduction of amortization expense for intangible assets. If realized benefits are attributed to post-reorganization amounts, the benefit is recognized as a reduction of income tax expense.

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 "— 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.

In addition, with respect to our UK leases described below under "— Liquidity and Capital Resources — UK Leases," we have estimated the fair value of a specific tax exposure for contingent liabilities related to a tax indemnity for the leases using a probability-weighted value based on a range of possible outcomes. We have recorded a £16.7 million (approximately $28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. As of December 31, 2003, that liability amounted to $29.5 million. For various reasons, including the fact that our leases differ qualitatively from the lease structure at issue in pending legal proceedings involving third parties, we believe it is unlikely that our leases will be successfully challenged by the Inland Revenue. If, however, the Inland Revenue does successfully challenge one or more of our lease arrangements, we could be liable for substantially increased amounts under the leases. We believe that it is likely that the final outcome of this issue will be significantly lower or higher than the $29.5 million accrued liability as of December 31, 2003, which could have a material effect on our results of operations, financial condition and liquidity in future periods.

Seasonality

Our Marine Geophysical segment experiences seasonality as a result of weather-related factors. Our first and fourth quarter, in particular, are generally negatively affected by adverse weather conditions in the North Sea, which prevent the full operation of seismic crews and vessels. 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 and Pertra generally do not experience material seasonal affects, 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. Our results are influenced by oil and natural gas industry capital expenditure budgets and spending patterns. These budgets are not necessarily spent in equal or progressive increments during the year, with spending patterns affected by individual customer requirements and industry-wide conditions. In addition, under our revenue recognition policy, revenue recognition from data licensing contracts is dependent, 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 data revenue does not necessarily flow evenly or progressively during a year or from year to year.

Results of Operations

Overview

Our results of operations for the years 2003 (Successor and Predecessor), 2002 and 2001 (as restated) 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, which included changes in the carrying value of assets and liabilities and changes to certain accounting policies.

In addition, the results of operations presented below excludes the results from our Production Services subsidiary (formerly Atlantic Power Group), our Atlantis oil and natural gas subsidiary and our Tigress software subsidiary, all of which were sold in 2002 or 2003 and are presented as discontinued operations in our financial statements included in Item 18 of this annual report.

We present operating results below based on our four business segments — Marine Geophysical, Onshore, Production and Pertra. 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 generates oil production from its 70% interest in PL 038 in the Norwegian 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	Predecessor Company	
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Twelve months ended December 31, 2003	Year ended December 31, 2002	Year ended December 31, 2001
					(Restated)
	(In thousands of dollars)				
Marine Geophysical					
Contract	$ 48,273	$302,451	$ 350,724	$ 282,234	$217,271
Multi-client pre-funding	6,510	43,187	49,697	100,326	66,951
Multi-client late sales	36,786	123,435	160,221	173,128	172,186
Other	7,813	31,040	38,853	31,952	29,967
	99,382	500,113	599,495	587,640	486,375
Onshore					
Contract	18,442	106,324	124,766	102,868	84,691
Multi-client pre-funding	1,807	14,636	16,443	14,104	9,011
Multi-client late sales	1,210	8,005	9,215	1,726	4,833
	21,459	128,965	150,424	118,698	98,535
Production					
Petrojarl1	11,086	58,529	69,615	62,631	20,269
Petrojarl Foinaven	18,726	93,373	112,099	133,364	124,059
Ramform Banff	6,572	38,616	45,188	37,886	47,357
Petrojarl Varg	8,604	59,191	67,795	69,455	87,715
Other	241	349	590	3,309	10,994
	45,229	250,058	295,287	306,645	290,394
Other/elimination	(3,243)	(29,369)	(32,612)	(2,449)	17,926
Total revenues (services)	162,827	849,767	1,012,594	1,010,534	893,230
Revenues (products) — Pertra	9,544	112,097	121,641	32,697	—
Total revenues	$172,371	$961,864	$1,134,235	$1,043,231	$893,230

Combined 2003 revenues for Predecessor and Successor were $91.0 million (9%) greater than 2002 revenues, due to increased revenues in Marine Geophysical, Onshore and Pertra, partially offset by decreased revenues in Production. Total revenues for 2002 were $150.0 million (17%) greater than 2001 revenues, with substantial increases in each business segment in 2002 as compared to the prior year. Pertra was not a part of our company in 2001.

Marine Geophysical 2003 (combined) revenues increased by $11.9 million (2%) as compared with 2002. Revenues from contract seismic acquisition increased by $68.5 million (24%) as a result of our strategy to increase our focus on the contract market. Revenues from multi-client pre-funding decreased $50.6 million (50%). Our acquisition of multi-client data was reduced significantly, while the pre-funding achieved as a percentage of cash investments in multi-client data was 72% in 2003 (combined) compared to 76% in 2002. Multi-client late sales decreased $12.9 million (7%) from 2002 to 2003. In 2003, we allocated a substantially larger percentage of the active vessel time for our seismic vessel fleet to contract acquisition rather than multi-client acquisition as compared to 2002.

From 2001 to 2002, we experienced substantial increases in both contract and multi-client pre-funding sales. Total revenue increased from 2001 to 2002 by $101.2 million (21%), one of our best year-on-year improvements, caused primarily by higher contract revenues and higher pre-funding on our multi-client projects.

Onshore revenues for 2003 (combined) increased by $31.7 million (27%) as compared with 2002. Onshore realized a significant increase both in contract and multi-client revenues due to major new contracts in Latin America and stronger North America multi-client late sales. From 2001 to 2002, Onshore revenues increased by $20.2 million (20%) as our operations in Latin America began to grow. In total, Onshore revenues increased by over $50 million from 2001 to 2003, reflecting the increased focus and growth in Latin America (particularly Mexico) and the increased multi-client sales in the United States, partially offset by reduced activities in Saudi Arabia.

Production revenues decreased by $11.4 million (4%) in 2003 (combined) as compared with 2002. This reduction was primarily attributable to a $21.3 million decline in revenues for *Petrojarl Foinaven,* reflecting both a general decline in the production level of the field and a temporary reduction in production due to problems with one of the compressors from late June through October 2003. *Petrojarl I* revenues increased in 2003 due to improvements in the production contract for the Glitne field. Revenues from *Ramform Banff* increased as a result of a temporary increase in production resulting from an additional production well drilled early in 2003. However, production from that well subsequently declined. Revenues from *Petrojarl Varg* decreased in 2003 due to a reduction in the day rate mid 2002 and conversion from a fixed day rate to a pure production tariff in August 2002 when we acquired 70% of PL 038, which includes the Varg field. The *Petrojarl Varg* contract was further amended, effective from May 29, 2004, to change the compensation structure to a combination of a fixed day rate and a production tariff.

Revenues for Production in 2002 were $16.3 million (6%) higher than 2001. The increase in 2002 was primarily attributable to increased revenues for *Petrojarl I* and *Petrojarl Foinaven.* Revenues for *Petrojarl I* increased by $42.4 million (209%) from 2001 to 2002, reflecting the start up of production on the Glitne field, which commenced in the third quarter 2001. Prior to Glitne start up, the vessel underwent major maintenance and upgrade work at the shipyard and was out of production for most of 2001. Revenues from *Petrojarl Foinaven* for 2002 were $9.3 million (8%) higher than 2001, reflecting the effects of a production capacity upgrade, undertaken mid 2001, and an increase in production from the field. Revenues from *Ramform Banff* for 2002 were $9.5 million lower than 2001 despite the fact that the vessel was at the shipyard for an upgrade during the first three months of 2001 and had a full year of operation in 2002. The decline was caused by a significant reduction in production from the field. *Petrojarl Varg* revenues, including the inter company revenues from Pertra, decreased by $18.3 million (21%) in 2002 compared to 2001 primarily due to reduced production from the Varg field.

Since August 2002, 70% of *Petrojarl Varg* revenues relates to Pertra's interest in the Varg field. These inter-segment revenues, which aggregated $45.1 million and $14.9 million in 2003 (combined) and 2002, respectively, are eliminated in our consolidated statement of operations.

Pertra revenues increased by $88.9 million (272%) in 2003 (combined) compared to 2002, as Pertra became the 70% owner and operator of PL 038 in August 2002. As a result, 2002 revenues reflect only the last five months of the year. As indicated above, our 2001 results do not include any revenues from Pertra. Petra's net production in 2003 (combined) was 4,056,083 barrels, with an average realized price of $29.37 per barrel. In 2002 (which included production from August through December), Petra's net production was 1,297,767 barrels, with an average realized price of $27.87 per barrel.

Cost of Sales

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

	Successor Company	Predecessor Company	Combined	Predecessor Company	
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Twelve months ended December 31, 2003	Year ended December 31, 2002	Year ended December 31, 2001 (Restated)
	(In thousands of dollars, except percentage data)				
Marine Geophysical	$55,903	$248,965	$304,868	$281,324	$254,456
% of revenue	56.3%	49.8%	50.9%	47.9%	52.3%
Onshore	$13,043	$ 76,634	$ 89,677	$ 98,769	$112,546
% of revenue	60.8%	59.4%	59.6%	83.2%	114.2%
Production	$21,208	$133,114	$154,322	$144,261	$180,130
% of revenue	46.9%	53.2%	52.3%	47.0%	62.0%
Other	$ 900	$ 6,776	$ 7,676	$ 4,286	$ 9,942
Transfer of cost(1)	(354)	(11,093)	(11,447)	1,746	—
Total cost of sales (services)	$90,700	$454,396	$545,096	$530,386	$557,074
% of revenue	55.7%	53.5%	53.8%	52.5%	62.4%
Cost of sales (products)					
Pertra	$11,384	$ 61,910	$ 73,294	$ 27,430	$ —
Elimination(1)	(5,130)	(28,528)	(33,658)	(16,629)	—
Total cost of sales (products)	$ 6,254	$ 33,382	$ 39,636	$ 10,801	$ —
% of revenue	65.5%	29.8%	32.6%	33.0%	—%
Total cost of sales	$96,954	$487,778	$584,732	$541,187	$557,074
% of revenue	56.2%	50.7%	51.6%	51.9%	62.4%

(1) After elimination of charterhire/transfer of cost related to Petrojarl Varg.

Cost of sales services increased $14.7 million in 2003 (combined) as compared with 2002 primarily due to reduced multi-client activity in our Marine Geophysical business, which had the effect of reducing the amount of costs capitalized as multi-client investment by $63.8 million, resulting from our increased focus during 2003 on contract marine seismic acquisition as compared to 2002. Excluding the effect of costs capitalized as multi-client investment, Marine Geophysical, Onshore and Production continued to show significant cost improvements in 2003, after having reduced costs significantly in 2002. Cost of sales services decreased $26.7 million in 2002 compared with 2001 primarily as a result of substantial cost reductions in Onshore and Production in 2002. Most of the cost reduction in Production related to reduced repair and maintenance costs. We had substantial repair and maintenance costs in 2001 related to the *Ramform Banff* and *Petrojarl I.* Both vessels were at the shipyard during the first part of 2001.

Cost of sales products increased $28.8 million in 2003 compared with 2002 as a result of an increase in Pertra operating costs due to a full year of operation in 2003 compared with only five months in 2002. We had no cost of sales products 2001 as Pertra was not part of our consolidated group in that year.

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 equipment (including seismic vessels), 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 ("MCDL Amortization"), the amortization of certain intangible assets recognized upon our adoption of fresh start reporting effective as of November 1, 2003 and goodwill amortization for the year ended December 31, 2001.

The following table shows our total DD&A expenses by segment. With respect to our Marine Geophysical and Onshore segments, we have provided (1) DD&A expenses excluding MCDL Amortization ("Adjusted DD&A") and (2) MCDL Amortization because we believe that separately disclosing MCDL Amortization provides investors useful information about a key component impacting the results of our geophysical operations.

	Successor Company	Predecessor Company	Combined	Predecessor Company	
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Twelve months ended December 31, 2003	Year ended December 31, 2002	Year ended December 31, 2001
	(In thousands of dollars)				Restated
Marine Geophysical:					
Adjusted DD&A	$ 7,556	$ 59,730	$ 67,286	$ 64,616	$ 60,385
MCDL amortization	29,786	131,485	161,271	183,317	173,452
DD&A	37,342	191,215	228,557	247,933	233,837
Onshore:					
Adjusted DD&A	3,251	14,292	17,543	17,077	6,340
MCDL amortization	2,653	15,133	17,786	11,331	7,539
DD&A	5,904	29,425	35,329	28,408	13,879
Production:					
DD&A	10,441	43,418	53,859	70,958	80,759
Pertra:					
DD&A	743	30,826	31,569	12,695	
Corporate and other:					
Adjusted DD&A	361	4,911	5,272	6,203	6,873
MCDL amortization	908	1,781	2,689	1,306	1,132
DD&A	1,269	6,692	7,961	7,509	8,005
Total:					
Adjusted DD&A	22,352	153,177	175,529	171,549	154,357
MCDL amortization	33,347	148,399	181,746	195,954	182,123
DD&A	$55,699	$301,576	$357,275	$367,503	$336,480

Adjusted DD&A for 2003 (combined) increased by $4.0 million (2%) compared with 2002, primarily due to increased depletion of oil and gas assets in Pertra (which was consolidated a full year in 2003 compared to five months in 2002), partly offset by the reduced depreciation in 2003 due to the impairment of *Ramform Banff* in 2002. Adjusted DD&A of the Predecessor was $153.2 million for the first ten months of 2003. Adjusted DD&A of the Successor was $22.4 million in the last two months of 2003 and was affected by the significant reduction in carrying value of $455.0 million after adoption of fresh start reporting effective as of November 1, 2003 and a reduction of estimates of useful lives adopted for depreciation of several of the assets in our seismic and FPSO fleet. MCDL Amortization was reduced in 2003 (combined) by $14.2 million (7%) as compared with 2002. The reduction relates to lower pre-funding and late-sales revenues, partially offset by a higher average amortization rate as a consequence of reduced sales forecasts and library impairments recorded in 2002 and 2003, and adoption of fresh start reporting as of November 1, 2003. MCDL Amortization for the ten months ended October 31, 2003 and the two months ended December 31, 2003 were $148.4 million and $33.3 million, respectively.

Adjusted DD&A expenses for 2002 increased by $17.2 million (11%) as compared with 2001, primarily due to the acquisition of a 70% interest in the Varg field (Pertra) and a significant increase in activities and equipment in Onshore. DD&A in Production decreased by $9.8 million (12%) primarily due to the impairment of *Ramform Banff* recognized in the third quarter of 2002 and reduced goodwill amortizations. MCDL Amortization increased $13.8 million (8%) in 2002 compared to 2001, primarily as a result of higher multi-client pre-funding sales.

Selling, General and Administrative Costs

Selling, general and administrative costs decreased $1.7 million in 2003 (combined) as compared with 2002 and $8.6 million in 2002 as compared with 2001 primarily as a result of our cost reduction efforts in this area over the last two fiscal years.

Impairments and other operating (income) expense, net

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 related to other assets and equipment. In 2002 we had impairments totaling $558.5 million, which included impairment of multi-client library of $200.4 million and impairment of seismic equipment and geophysical assets of $16.7 million. We also recorded an impairment of $332.0 million on *Ramform Banff* as a result of negative development of the field and decreased prospects for redeployment alternatives. Impairments in 2001 aggregated $12.7 million and related primarily to the multi-client library.

We recorded other operating (income) expense, net, of $22.4 million in 2003 (combined), primarily relating to severance payments that aggregated $19.8 million. We had other operating (income) expense, net, of $8.5 million in 2002 and $(125.6) million in 2001. The 2001 amount includes a gain of $137.0 million from the sale of our data management business.

Interest expense and other financial items

Interest expense for 2003 totaled $99.0 million for the first ten months (Predecessor) and $16.9 million for the last two months (Successor), compared to $153.3 million in 2002 and $151.6 million in 2001. Our interest expense declined substantially in 2003 because most of our debt did not accrue interest while we were in Chapter 11 proceedings and because of the significant reduction of our interest bearing debt after emerging from Chapter 11 in November 2003.

Income from equity investments totaled $1.0 million in 2003 (combined), compared to a loss of $11.5 million in 2002 and a loss of $0.7 million in 2001.

Other financial items for 2003 (combined) was a net expense of $5.7 million compared to a net gain of $33.8 million in 2002. The amount for 2002 included a gain of $45.3 million from tax equalization contracts, which were terminated in 2002.

Reorganization items

In 2003, in connection with our completed Chapter 11 reorganization, we recorded the following reorganization items in our consolidated statement of operations:

- 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 cost of reorganization;
- for the first ten months (Predecessor) we recorded the net effect at November 1, 2003, of adopting fresh start reporting of $532.3 million. The 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 "— Financial Restructuring" in Item 5 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 "Fresh Start Reporting and

Changes in Accounting Policies" in Item 5 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 $18.1 million in 2003 (combined) compared with $185.9 million in 2002 and $28.3 million in 2001, excluding tax relating to discontinued operations. Tax expense in 2003 included taxes payable of $24.0 million and net deferred tax benefits of $5.9 million. Taxes payable related primarily to foreign taxes in regions where we are deemed to have a permanent establishment and to Pertra, which is subject to petroleum taxation rules in Norway at a nominal tax rate of 78%. Under the petroleum taxation rules, it is not possible for Pertra to offset its income against losses from other operations. Income tax expense in 2002 included taxes payable of $23.8 million and net deferred taxes of $162.1 million, which reflects a substantial change in deferred taxes in connection with exit from the shipping tax regime in Norway in 2002 and 2001 and a valuation allowance related to deferred tax asset of $61.1 million. Income tax expense in 2001 included taxes payable of $6.9 million and net deferred taxes of $21.5 million.

Discontinued Operations

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). In 2002 we had $201.1 million in loss from discontinued operations, net of tax, which included a loss related to the investment in our Atlantis subsidiary (sale completed February 2003) of $174.5 million and a loss of $22.6 million related to our investment in Production Services subsidiary (sale completed December 2002).

Operating profit (loss) and net income (loss)

Operating profit for 2003 was $9.8 million for the first ten months (Predecessor), which included impairment charges and other operating (income) expense totaling $116.3 million, and $10.7 million for the last two months (Successor), which included other operating (income) expense totaling $1.1 million. In 2002 we reported an operating loss of $488.6 million, after impairment charges of $558.5 million and other operating (income) expense of $8.5 million.

For 2003 we reported a 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 gain on debt discharge of $1,253.9 million, adoption of fresh start reporting ($532.3 million), and impairment charges ($95.0 million). Net losses for 2002 and 2001 were $1,174.7 million and $172.5 million, respectively.

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 the following:

- the development of our main market drivers, which includes prices and price expectations for oil and natural gas. Such prices and price expectations have a direct impact on the revenues of our oil and natural gas activities and also affect the demand for both 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 grow 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 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 primary emphasis on contract work; and
  - implementation of a streamer replacement program for our seismic vessels;
- the production profile of the Varg field in light of our continued efforts to enhance oil recovery;
- our ability to capitalize on Pertra's position and interests on the NCS to gain access to exploration acreage and to discover new reserves that can be developed;
- 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 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;
- our ability to continue to develop or acquire competitive technological solutions for our different business units;
- resolution of the uncertainty regarding our UK vessel leases as described under "Key Information — Risk Factors — Risk Factors Relating to Our Indebtedness and Other Obligations — Potentially increased payments under vessel lease arrangements may adversely affect our financial condition, future results of operations and liquidity" in Item 3 of this annual report, and regarding possible tax exposure to Norwegian taxing authorities as discussed under "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.

Liquidity and Capital Resources

Liquidity — General

Subject to the discussion below under "— UK Leases," we believe that our cash balances and our available borrowing capacity under our revolving credit facility will be adequate to meet our working capital and liquidity needs for the remainder of 2004 and 2005. While we believe that we have adequate sources of funds to meet our liquidity needs for the 2004-2005 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 $105.2 million at December 31, 2003, an increase from $91.6 million at December 31, 2002. At year-end 2003, we had distributed $17.9 million of the excess cash to creditors under the terms of our plan of reorganization entered into in connection with our financial restructuring that became effective as of November 5, 2003. We distributed the remaining excess cash of $22.7 million in May 2004, and that amount is included in our December 31, 2003 balance sheet in other accrued expenses. The payment of this remaining amount was contingent on the establishment of a $110 million two-year secured working capital facility, which was established in March 2004 as described below.

Net cash provided by operating activities totaled $247.0 million in 2003 (combined), representing a decrease of $46.0 million compared with 2002. Cash flows from operating activities for 2003 were significantly impacted by the effects of the financial restructuring that we completed during 2003. Net income (loss) declined by $41.5 million in 2003 as compared with 2002, after reflecting the non-cash effects of the 2003 restructuring ($1,253.9 million), changes in impairments and fresh start adoption in 2003 compared with 2002 ($308.5 million) and changes in deferred income taxes ($179.5 million). Operating cash flow was negatively impacted by changes in other items aggregating $96.8 million from 2002 to 2003 (combined), offset by a positive impact caused by a reduction in accounts receivable aggregating $64.1 million in 2003 as compared with 2002.

Our external sources of liquidity include our secured revolving credit facility, equipment financing and trade credit. Subject to our coming into compliance with reporting obligations under the U.S. federal securities laws, market conditions, availability of credit ratings and other factors, we might also seek to raise debt or equity in the capital markets.

In March 2004, we entered into a secured $110 million credit facility consisting of a $70 million revolving credit facility and a $40 million letter of credit facility. We can borrow U.S. dollars under the revolving credit facility for working capital and general corporate purposes, and the letter of credit facility can be utilized in multiple currencies to obtain letters of credit to secure, among other things, performance and bid bonds required in our ongoing business. The credit facility matures in March 2006 and is secured by various of our assets. Borrowings under the facility bear interest at LIBOR plus 2%.

As of December 31, 2003, interest bearing debt and capital lease obligations were approximately $1,211 million and net interest bearing debt (interest bearing debt and capital lease obligations less cash and cash equivalents and restricted cash, adjusted for the final excess cash distribution) was approximately $1,077 million.

Certain of our loan and lease agreements and our senior note indenture contain requirements to provide audited U.S. GAAP financial statements by June 30 of each year and to provide unaudited U.S. GAAP quarterly financial statements within a specified period (typically 60 days) after the end of each of the first three quarters. We have received waivers from the various lenders allowing us to report under those agreements and the indenture under Norwegian GAAP in lieu of U.S. GAAP until June 30, 2005.

In addition to customary representations and warranties, certain of our debt agreements contain covenants restricting us from incurring debt unless specified coverage ratios are met and limiting our financial indebtedness, excluding project debt, to $1.5 billion. These agreements also contain other restrictions as described in note 15 to the consolidated financial statements included in Item 18 of this annual report. See "Key Information — Risk Factors — Risk Factors Relating to Our Indebtedness and Other Obligations — Our debt agreements may limit our flexibility in responding to changing market conditions or in pursuing business opportunities" in Item 3 of this annual report.

For a description of limitations on the ability of our Norwegian subsidiaries to pay dividends to us, please see "Financial Information — Dividend Restrictions" in Item 8 of this annual report. We do not expect these limitations to affect in a material way our ability to meet our cash obligations.

For information relating to our outstanding indebtedness as of December 31, 2003 and the maturities of such indebtedness, please see note 15 of the notes to our consolidated financial statements in Item 18 of this annual report.

Net Cash Used in Investing and Financing Activities

Net cash used in investing activities totaled $94.8 million in 2003 (combined), of which $69.7 million related to the first ten months of the year (Predecessor) and $25.1 million related to the last two months (Successor). Such amount represents a decrease of $179.7 million compared to the total net cash used in investing activities in 2002. We achieved this reduction in investing activities primarily through (a) a $61.0 reduction in cash investment in multi-client library and (b) a $75.9 million reduction in capital expenditures effected primarily by selling our Atlantis oil and gas subsidiary and certain other businesses.

Net cash used in financing activities totaled $138.6 million in 2003 (combined), of which $116.6 million related to the first ten months of the year (Predecessor) and $22.0 million related to the last two months (Successor). The total for 2003 represents an increase of $132.6 million compared to 2002. Of this increase, approximately $75.4 million represents an increase in net repayment of long-term debt and principal payments under capital leases due to a reduction in borrowings in 2003 because of our financial difficulties. An additional $19.9 million of the increase in net cash used in financing activities for 2003 resulted from an increase in restricted cash due primarily to increased cash deposits used to collateralize bid bonds. In addition, in December 2003, we made the first distribution of cash, totaling $17.9 million, to creditors under our reorganization plan.

Capital Requirements and Commitments

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

- capital expenditures on seismic vessels and equipment, including data processing equipment;
- capital expenditures on FPSO vessels and equipment;
- capital expenditures relating to exploration for and development of oil reserves in Pertra;
- investments in our multi-client library; and
- working capital related to growth, seasonality and specific project requirements.

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 2003, with the exception of expenditures in Pertra to explore and develop the Varg field, we did not make significant capital expenditures to increase capacity.

The following table sets forth our consolidated capital expenditures (which does not include our investment in multi-client library) for continuing operations in 2003 (in millions):

Segment	Amount
Marine Geophysical	$16.1
Onshore	7.0
Production	0.5
Pertra	34.2
Other	0.3
Total	$58.1

For 2004, we expect:

- to decrease our investment in multi-client library as compared to 2003 by continuing to focus on the contract market;
- capital expenditures in Marine Geophysical to increase significantly to approximately $55-60 million as a result of increases in replacements of equipment for our seismic fleet, increased investment in data processing equipment and commencement of our streamer replacement program;
- capital expenditures in our Onshore and Production segments to continue at relatively low levels because (a) we generally have a sufficient inventory of most equipment in our Onshore operations and (b) our FPSO vessels are not expected to have substantial replacement needs through 2004; and
- our oil and natural gas subsidiary Pertra will drill a number of development wells and one exploration well in PL 038 in 2004. Capital expenditures related to these drilling activities are expected to aggregate $80 million to $90 million depending on progress.

As of October 31, 2004, we did not have any material commitments for future capital expenditures in our Marine Geophysical, Onshore or Production segments, except for equipment orders consistent with the descriptions above.

In Pertra, we have the following commitments:

- On PL 321, where Pertra is operator and holds an 80% interest, the license terms require us to acquire 500 square kilometers of seismic data by June 2010. In September 2004, Pertra, on behalf of the license owners, entered into a contract with our Marine Geophysical group to acquire 800 square kilometers of seismic data at a total cost of $7.7 million for Pertra's share, before tax allowances. By June 2007, we are required to decide whether to drill one firm and one optional exploration well or relinquish the area.
- On PL 316, where Pertra holds a 30% interest, the license terms require us to purchase an additional 800 kilometers of seismic data and drill at least one exploration well by June 2010. We estimate the total amount required to purchase the seismic data and to drill the mandatory well to be approximately $9 million for Pertra's share, before tax allowances.

As of October 31, 2004, our Pertra subsidiary was also in the process of securing rig capacity for 2005 for drilling development and appraisal wells on PL 038. We expect to commit to drilling four wells at an estimated rig cost of $28 million for Pertra's share, before tax allowances, with the option to drill up to three additional wells.

In addition, we expect to spend approximately $25 million per year through 2008 to upgrade our marine seismic streamers. Since this program is discretionary, however, we may in the future change the scope and annual capital expenditure related to the program. We intend to make other capital expenditures in our business segments as conditions dictate and financial resources permit. 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 also expect to continue to exploit opportunities in Pertra that could result in significant capital outlays from time to time.

Long-Term Contractual Obligations

The following table presents our long-term contractual obligations and related payments due in total and by year as of December 31, 2003:

Contractual obligations	Payments due by period Total	2004	2005 - 2006	2007 - 2008	thereafter
	(In millions of dollars)				
Long term debt obligations	$1,127.2	$18.5	$283.0	$27.6	$798.1
Operating lease obligations	158.8	50.4	45.0	33.7	29.7
Capital lease obligations	89.3	22.7	52.6	14.0	—
Totals	$1,375.3	$91.6	$380.6	$75.3	$827.8

For additional information about the components of our long-term debt and lease obligations, please refer to notes 15 and 19 to the consolidated financial statements included in Item 18 of this annual report.

The table above does not include our accrued pension liability related to our defined benefit pension plans, which as of December 31, 2003 totaled $45.2 million. This liability represents the aggregate shortfall of pension plan assets compared to projected benefit obligations for our plans. This obligation will be paid by us 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. Such requirements are subject to change over time, but we expect these payments to be made over several years. Please read note 21 of the notes to our consolidated financial statements in Item 18 of this annual report for additional information relating to our defined benefit plans.

UK Leases

We have entered into vessel lease arrangements for five of our Ramform design seismic vessels, our FPSO vessel *Petrojarl Foinaven* and the topsides of our FPSO vessel *Ramform Banff.* In general, under the leases, UK financial institutions acquired the assets from third parties, and we leased the assets from the lessors under long-term charters that give us the option to purchase the assets for a bargain purchase price amount at the end of the charter periods. The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Under these leases, we indemnified the lessors against specified future events that could reduce their expected after-tax returns, including potential changes in UK tax laws and interpretations thereof and changes in interest rates, as the leases are based on assumed interest rates.

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%. 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. During 2003, 2002 and 2001, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $1.5 million, $3.9 million and $1.5 million in the ten months ended October 31, 2003 and the years ended December 31, 2002 and 2001, respectively.

The UK Inland Revenue ("Inland Revenue") has not signed off on the lessors' claims to capital allowances related to our leases. We understand that the Inland Revenue has generally deferred signing off on defeased leases (not just ours) pending the outcome of a case that has been appealed to the House of Lords, the highest UK court of appeal. We expect a decision from the House of Lords in late 2004. In that case, the Inland Revenue is challenging capital allowances associated with a defeased lease. If the House of Lords rules in favor of the Inland Revenue's position, there is a high likelihood that the Inland Revenue will also challenge other defeased leases.

For various reasons, including the fact that our leases differ qualitatively from those at issue in the pending legal proceeding described above, we believe it is unlikely that our leases will be successfully challenged by the Inland Revenue. In addition, we believe that any such challenge would likely involve a lengthy process, including both trial and appellate proceedings possibly extending over several years, to fully resolve the relevant issues. As a result, at this point we have not considered appropriate to establish available sources of liquidity other than our revolving credit facility to permit us to make any necessary payments that might be required under the terms of our leases. If we were to become liable for a substantial amount as a result of a successful challenge to our leases by the Inland Revenue, we may not have sources of liquidity that would permit us to pay the entire amount of such a possible liability, which could be very large. As a result, we could be required to seek additional sources of financing and possibly take other measures such as reducing or delaying capital expenditures and/or selling assets. We may not be able to take all of the actions necessary to meet these potential additional obligations on satisfactory terms or at all. As a result, if our leases were successfully challenged, it would likely have a material adverse affect on our financial condition, future results of operations and liquidity.

In addition, the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available under the UK lease related to the *Petrojarl Foinaven.* 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 correspondingly increase (and then decrease).

Please read "Key Information — Risk Factors — Risk Factors Relating to Our Indebtedness and Other Obligations — Potentially increased payments under vessel lease arrangements may adversely affect our financial condition, future results of operations and liquidity" in Item 3, "Financial Information — Legal Proceedings — UK Legal Proceedings Involving Third Parties" in Item 8 and note 19 of the notes to our consolidated financial statements in Item 18 of this annual report for additional information relating to these UK lease matters.

Research and Development

We incurred research and development costs of $2.6 million, $2.8 million and $3.8 million during the years ended December 31, 2003, 2002 and 2001, 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 October 31, 2004:

Name (Age)	Position	Director since	Term expires	Share Ownership
Jens Ultveit-Moe (62)	Chairman	2002	2005	9.6%(1)
Francis Gugen (55)	Director	2003	2005	*
Keith Henry (59)	Director	2003	2005	*
Harald Norvik (58)	Director	2003	2005	*
Rolf Erik Rolfsen (64)	Director	2002	2005	*
Clare Spottiswoode (51)	Director	2003	2005	*
Anthony Tripodo (52)	Director	2003	2005	*

(1) Controlled through Umoe Invest AS

* Less than 1% of our outstanding shares as of October 31, 2004.

Mr. Ultveit-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. Ultveit-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. Ultveit-Moe was an associate with McKinsey & Company, Inc. in New York and London. He is chairman of the board of directors of Unitor ASA and Kverneland ASA. Mr. Ultveit-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. 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 has his educational background from Nottingham University, in addition to qualifying as a UK chartered accountant.

Mr. Henry served as group executive vice president for the Kvaerner Engineering and Construction Group from March 2000 until June 2003. Mr. Henry was chief executive of National Power Plc from 1995 to 1999 and was chief executive of Brown & Root Ltd from 1990 to 1995. He acts as a non-executive director and as an advisor to a number of energy, construction and energy related organizations. He holds BSc and MSc degrees, and is a Fellow of the Royal Academy of Engineering.

Mr. Norvik is chairman and a partner of Econ Management. He served as chief executive officer of Statoil 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 boards of Busybees and Economatters Ltd. and is a non-executive director of Advanced Technology (UK) plc, and Tullow Oil plc. She has 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 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.

Currently there are two alternate directors, Marianne Elisabeth Johnsen and John Reynolds. As alternate directors they are available to fill in as needed on a meeting to meeting basis if a regular director is unable to attend and are also eligible to fill a vacancy on the board caused by a departure of a regular board member.

Ms. Johnsen is partner and founder of X-lence Group, a management consultancy and business strategy company. Until the end of 2002 she was Vice President Strategy and Business Development Elkem Shared Services Division at Elkem ASA. From 1993 to 1997, she was Head of the Legal Section and Administration Department at Ullevaal University Hospital. She has also had positions in Norwegian Ministry of Foreign Affairs and Norwegian Ministry of Justice. She serves on the boards of several companies: Fjord Seafood ASA, Handicare ASA, Odin Fund Management AS and Norwegian Refugee Council. She has previously served on boards for Ementor ASA and Aker University Hospital. She holds a law degree from the University of Oslo and received a master's degree with honors in business administration (MBA) from the Solvay Business School in Brussels, Belgium.

Mr. Reynolds is managing director of Houlihan Lokey Howard & Zukin (Europe) Ltd., an investment bank. He has a master's in theology and religious studies from Cambridge University, and is a fellow of the Institution of Electrical Engineers and a fellow of the Energy Institute.

Audit and Remuneration Committees of the Board

Our audit committee currently consists of three members, Messrs. Gugen (chairman), Norvik and Tripodo. 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 under applicable Norwegian and other laws 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 auditors 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, 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 auditors, 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.

Our remuneration committee consists of Messrs. Henry (chairman) and Rolfsen. The remuneration committee establishes and reviews overall policy and structure with respect to compensation and incentive matters, including the determination of compensation and incentive arrangements for directors, executive officers and key employees. Our remuneration committee has adopted a written charter, a copy of which we have filed as an exhibit to this annual report.

Supermajority Voting Provision Relating to Our Board

Under our Amended Articles of Association, any change to our Board of Directors prior to October 16, 2005 will require approval by the holders of more than two-thirds of the votes cast as well as of the shares represented at the shareholders meeting. In addition, as part of our 2003 restructuring, our shareholders resolved that board decisions on certain specified major transactions, during the same two year period, must be approved by the board members nominated by the pre-restructuring shareholders or their successors. These major transactions include:

- any single sale of assets or series of sales of assets, in any calendar year, in excess of $100 million and not otherwise requiring approval by two-thirds of the shareholders in a general meeting;
- changes to our key executive management;
- new financings or borrowings over $25 million;
- application of "major proceeds," which means the proceeds from the sale of any of our assets in excess of $100 million
- material acquisitions, which includes any single acquisition of assets or series of acquisition of assets, in any calendar year, in excess of $100 million and not otherwise requiring approval by two-thirds of the shareholders present and voting in a general meeting;
- proposals to change our Articles of Association; and
- proposals for issuance of new equity or equity-like securities.

Any changes to these instructions require approval by the holders of more than two-thirds of the votes cast and of the shares represented at the shareholders meeting.

Executive Officers

The table below provides information about our executive officers as of October 31, 2004:

Name (Age)	Position	Executive officer since	Share Ownership
Svein Rennemo (57)	President and Chief Executive Officer	2002	*
Gottfred Langseth (38)	Senior Vice President and Chief Financial Officer	2004	*
Rune Eng (43)	President — Marine Geophysical	2004	*
Eric Wersich (41)	President — Onshore	2003	*
Sverre Skogen (48)	President — Production	2003	*
Erik Haugane (51)	Managing Director — Pertra	2003	*
Anthony Ross Mackewn (57)	Senior Vice President — Geophysical	1999	*
Andreas J. Enger (42)	Senior Vice President — Group Planning	2003	*

* Less than 1% of our outstanding shares as of October 31, 2004.

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 1982, 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 board member of Dynea of Finland and Nutreco of the Netherlands.

Mr. Langseth joined PGS as senior vice president and chief financial officer in January 2004. He was chief financial officer at Ementor ASA (Merkantildata) from 2000 to August 2003. Mr. Langseth was senior vice president of finance and control for Aker Maritime from 1997 to 2000. He served with Arthur Andersen Norway from 1991 to 1997, qualifying as a Norwegian state authorized public accountant in 1991. Mr. Langseth has a masters 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 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. Skogen was appointed president of Production in January 2004. He previously served as independent advisor for various projects from January 2003 to January 2004. He was president and chief executive officer of Aker Kvaerner AS Oil & Gas from March 2002 to January 2003, president and chief executive officer of Aker Maritime ASA from May 1997 to March 2002 and executive vice president of Aker RGI from January 1997 to May 1997. Mr. Skogen was the founding partner of TerraMar Prosjektledelse and helped establish TerraMar Informasjonssystemer in 1993, which he headed until 1997. During the 1980s he held various positions in Norwegian Petroleum Consultants, the engineering contractor for a number of large developments on the Norwegian shelf. Mr. Skogen has a master's of science degree in construction management, a master's degree in business administration and a bachelor of science degree in civil engineering from the University of Colorado.

Mr. Haugane has been president of Pertra since its formation in January 2002. He joined PGS in 1992 as assistant manager of international development for PGS Nopec. He acted as the Asian business development manager for PGS Exploration from 1994 to 1996. Mr. Haugane was appointed account executive Norway in January 1997 and senior advisor to PGS ASA in 2000. Mr. Haugane has a master's degree in geology from the University of Tromsø.

Mr. Mackewn joined PGS as the technology director of PGS Nopec in 1993 and transferred to PGS Exploration in 1996 as managing director of PGS Exploration UK Ltd. He was appointed president of Exploration EAME in November 1999, president of PGS Geophysical Services in May 2001, president of PGS Marine Geophysical in February 2003 and group senior vice president of Geophysical in August 2004. Prior to joining PGS, Mr. Mackewn held a number of senior positions within the seismic services division of Schlumberger. Mr. Mackewn graduated with an honors degree in physics from the University of Southampton in 1969.

Mr. Enger joined PGS as vice president of group planning in January 2003. He was previously a partner at McKinsey & Company Inc., where he led their Middle East energy practice from 1999 to July 2002. He received a master of science degree in engineering cybernetics from the Norwegian Institute of Technology in 1985 and a master's degree with distinction in business administration from INSEAD, Fontainebleau in 1988.

Share Ownership of Directors and Executive Officers

As of October 31, 2004, the total number of our shares and ADSs beneficially held by our directors (7 persons) and executive officers (8 persons) as a group was 1,915,520, representing approximately 9.6% of our outstanding shares. Mr. Ultveit-Moe, chairman of our board of directors, is the founder, chief executive officer and president of Umoe Group, the parent company of Umoe Invest AS, which as of October 31, 2004 owned 1,912,444 shares, or 9.6% 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 October 31, 2004 we do not have board or shareholder authorization to issue shares under any share option plan. The establishment of any management incentive plan that includes the issuance of share options or other equity rights will require 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.

Compensation of Directors and Executive Officers

For the year ended December 31, 2003, the aggregate amount we paid for compensation to our directors and executive officers as a group for services in all capacities during 2003 was $3.0 million. This amount includes compensation paid to all persons who served as directors and executive officers during any period of 2003. Mr. Rennemo, our president and chief executive officer, received compensation for services to us during 2003 of $0.8 million. The aggregate benefits that had accrued to our directors and executive officers as a group (including all persons who served as such during any period of 2003) under our various defined benefit plans for the year ended December 31, 2003 was $0.7 million (including $0.3 million in settlement of a deferred pension liability for one of our former directors). Please read note 21 of the notes to our consolidated financial statements in Item 18 of this annual report for additional information relating to our defined benefit plans.

Employees

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

	December 31,		
	2003	2002	2001
Marine Geophysical	1,143	1,356	1,420
Onshore	1,479	1,828	946
Production	515	520	535
Pertra	5	6	—
Global Services/Corporate	235	252	291
Discontinued Operations	—	41	1,953
Total	3,377	4,003	5,145

Except for the employee lockout affecting the FPSO *Petrojarl I* and the strike affecting *Petrojarl Varg* as described in Item 4 of this annual report under the captions "Information on the Company — Our Production Segment — Employee Lockout and Strike in September/October 2004," we have not experienced any material work stoppages related to union activities and consider our relations with our employees to be good.

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. For 2004, our board of directors has authorized a new performance bonus incentive scheme for our chief executive officer and other executive officers. Under this scheme, the chief executive officer is entitled to a cash bonus of up to 50% of base salary and a share purchase bonus of up to 30% of base salary. Other executive officers are entitled to a cash bonus of up to 40% of base salary and a share purchase bonus of up to 20% of base salary. Within these limits, bonus will be determined on the basis of achievement or overachievement of financial and non-financial performance targets. Any amount received as a share purchase bonus, on a pre-tax basis, is required to be used to buy our shares in the open market at market price, which must be held for a minimum of three years. Implementation of the share purchase bonus is subject to compliance with any and all applicable legal requirements.

ITEM 7. *Major Shareholders and Related Party Transactions*

We issued an aggregate of 20,000,000 new ordinary shares, each with a par value of NOK 30, at consummation of our Chapter 11 reorganization in November 2003. Our share ownership following consummation of the reorganization and the related rights offering is presented below:

	Shares of new PGS ordinary shares	Percent ownership
Former bondholders and bank debt holders	12,200,000	61.0%
Former trust preferred securities holders	1,000,000	5.0%
Pre-existing ordinary share holders	6,800,000	34.0%
Total	20,000,000	100.0%

Of the new ordinary shares issued, 4% were received by pre-existing shareholders in exchange for our old shares, receiving one new share for each approximately 129.18 pre-existing shares. The remaining 30% of our newly issued shares held by pre-existing shareholders were purchased in a rights offering that was underwritten by three of our major shareholders: Umoe AS ($60.0 million); Compagnie Generale de Geophysique ($22.0 million); and TS Industri Invest AS ($3.0 million). These underwriting shareholders received the right to acquire 1,500,000 in reserved shares as consideration for the underwriting. We distributed the cash proceeds from the rights offering to the former bank debt holders and bondholders who participated in the reorganization.

Based on a Schedule 13G filed with the Securities and Exchange Commission on January 16, 2004, Umoe Invest AS beneficially owns 1,912,444 shares, or 9.6% of our outstanding shares. Mr. Jens Ultveit-Moe, founder, chief executive officer and president of Umoe Group, the parent company of Umoe Invest AS, serves as chairman of our board of directors. Please read Item 6 of this annual report for additional information regarding Mr. Ultveit-Moe.

Based on a Schedule 13G filed with Securities and Exchange Commission on July 29, 2004, John A. Griffin beneficially owns 1,468,093 shares, or 7.3% of our outstanding shares. Mr. Griffin is the Managing Member of JAG Holdings LLC and JAG Offshore Holdings LLC, and in that capacity directs their operations. JAG Holdings LLC is the general partner of Blue Ridge Limited Partnership, and JAG Offshore Holdings LLC is the general partner of Blue Ridge Offshore Master Limited Partnership. Based on the Schedule 13G, Blue Ridge Limited Partnership and JAG Holdings LLC beneficially own 976,329 shares, or 4.9% of our outstanding shares; and Blue Ridge Offshore Master Limited Partnership and JAG Offshore Holdings LLC beneficially own 491,764 shares, or 2.5% of our outstanding shares.

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 December 31, 2003, there were 24 record holders of ADSs representing 7,019,341 shares, of which 19 had registered addresses in the United States. These 19 United States record holders held ADSs representing 7,019,341 shares, which represented approximately 35% 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, 2003, there were 20,000,000 ordinary shares outstanding (including shares represented by ADSs) held by 2,992 record holders, of which 49 had registered addresses in the United States and 2,739 had registered addresses in Norway. The United States holdings represented 9,369,727 shares, or approximately 47% 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 United States persons. The Norwegian holdings represented 2,526,321 shares, or approximately 13% of the total number of our shares outstanding as of that date.

In the late 1990s, bank loans were extended to various of our Norwegian employees, including some key management personnel and at least one director, in connection with the grant of options by us during that period. These loans were guaranteed by us, generally bore interest at 4% or 5% per annum and were intended to provide the individuals involved with funds required to pay Norwegian taxes that were triggered by option grants. The largest amount of outstanding loans from us to these employees during 2003 aggregated $1.7 million. Most of these loans were settled during 2003. As of October 31, 2004, the amount of these loans outstanding aggregated $0.3 million, with none of such outstanding loans being with any executive officers, directors or key management personnel.

Please read note 24 of the notes to our consolidated financial statements included in Item 18 of this annual report for additional information regarding our related-party transactions.

Item 8. *Financial Information*

Financial Statements

Please read Item 18 of this annual report.

Legal Proceedings

General

From time to time, we are involved in or threatened with various legal proceedings arising in the ordinary course of business. 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.

UK Legal Proceedings Involving Third Parties

We have entered into vessel lease arrangements for five of our Ramform design seismic vessels, our FPSO vessel *Petrojarl Foinaven* and the topsides of our FPSO vessel *Ramform Banff.* For a description of pending legal proceedings in the UK involving third parties that could affect our obligations under these lease arrangements, please read "Key Information — Risk Factors — Risk Factors Relating to Our Indebtedness and Other Obligations — Potentially increased payments under vessel lease arrangements may adversely affect our financial condition, future results of operations and liquidity" in Item 3 of this annual report.

We believe that the lease transaction and the lease structure involved in the UK proceedings described in Item 3 of this annual report are qualitatively different than those associated with our leases. Accordingly, even if the Inland Revenue is successful in challenging the contested lease, that fact does not necessarily mean that it would be successful challenging our leases. We intend to defend vigorously any challenge of our leases by the Inland Revenue. In addition, we believe that any such challenge would likely involve a lengthy process, including both trial and appellate proceedings possibly extending over several years, to fully resolve the relevant issues.

Dividend Restrictions

Our ability to meet parent company-level payment obligations depends upon dividends, distributions, advances and other intercompany 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 on an unconsolidated basis in accordance with Norwegian GAAP:

- the annual profit according to the income statement for the last financial year;
- retained profit from previous years;
- 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 sheet, 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. We do not currently intend to declare or pay dividends. Any future dividends will be subject to determination based upon our results of operations and financial condition, our future business prospects, any applicable legal or contractual restrictions, including those in our debt agreements, and other factors that the Board of Directors considers relevant.

Significant Changes

Except (a) as disclosed in this annual report or in our reports on Form 6-K dated May 19 and July 29, 2004 relating to our results of operations reported under Norwegian GAAP for the three months ended March 31 and June 30, 2004, respectively, and (b) any adjustments required to our interim 2004 financial statements to reflect the restatements reflected in the consolidated financial statements and related notes included in Item 18 of this annual report, no significant changes have occurred since the date of our 2003 annual financial statements.

ITEM 9. *The Offer and Listing*

Listing Details

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

Each ADS represents one share. Citibank, N.A. serves as the depositary for the ADSs. Prior to February 2003, the ADSs were traded on the New York Stock Exchange. 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."

In November 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." We are using our reasonable commercial efforts to list our ADSs on a national securities exchange.

You should be aware that trading in our ADSs through market makers and quotation on the Pink Sheets may involve risk, such as trades not being executed as quickly as when the securities were listed on the NYSE. Please read "Key Information — Risk Factors — Other Risk Factors — Because our ADSs currently do not trade on a national exchange, you may have difficulty trading in our ADSs" in Item 3 of this annual report.

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.

	Price per ADS	
Calendar Period	High	Low
1999	$24.19	$11.19
2000	19.56	10.00
2001	14.63	5.00
2002	7.89	0.35
2003 (through February 26, 2003)	0.48	0.31
2002		
First Quarter	7.89	4.81
Second Quarter	6.89	2.99
Third Quarter	3.52	0.39
Fourth Quarter	0.69	0.35

We have presented in the table below, for the periods indicated, the reported high and low closing prices for our ADSs on the Pink Sheets. Upon emergence from Chapter 11 proceedings and consummation of our financial restructuring, the pre-restructuring shareholders received one post-restructuring share per 129 old shares held in addition to the right to subscribe for new shares in a rights offering.

	Price per ADS	
Calendar Period	High	Low
2003 (February 26, 2003 - November 5, 2003)	$ 1.49	$ 0.10
2003 (from November 6, 2003)	43.00	32.80
2003 (from February 26, 2003)	43.00	0.10
First Quarter	0.20	0.10
Second Quarter	0.66	0.15
Third Quarter	1.03	0.58
Fourth Quarter (through November 5, 2003)	1.49	0.34
Fourth Quarter (from November 6, 2003)	43.00	32.80
2004		
First Quarter	51.20	38.05
Second Quarter	48.00	33.50
Last Six Months		
October	48.85	37.50
September	48.50	41.35
August	38.50	36.25
July	41.00	37.00
June	41.60	35.50
May	44.60	34.50

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. Upon emergence from Chapter 11 proceedings and consummation of our financial restructuring, the pre-restructuring shareholders received one post-restructuring share per 129 old shares held in addition to the right to subscribe for new shares in a rights offering.

Calendar Period	Price per share High	Price per share Low
1999	NOK185.5	NOK84.0
2000	174.0	91.5
2001	124.5	44.0
2002	70.0	2.6
2003 (through November 5, 2003)	10.9	1.1
2003 (from November 6, 2003)	315.0	213.0
2002		
First Quarter	70.0	41.0
Second Quarter	59.0	23.0
Third Quarter	27.5	2.6
Fourth Quarter	5.3	2.6
2003		
First Quarter	3.1	1.1
Second Quarter	5.1	1.1
Third Quarter	7.0	4.4
Fourth Quarter (through November 5, 2003)	10.9	6.9
Fourth Quarter (from November 6, 2003)	315.0	213.0
2004		
First Quarter	365.0	262.0
Second Quarter	337.0	245.0
Last Six Months		
October	330.0	293.5
September	330.0	278.0
August	277.5	248.5
July	289.0	265.0
June	292.5	254.0
May	310.0	245.0

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.

Before October 16, 2005, the election of a new director as a replacement for an incumbent director prior to the expiration of the term of the incumbent director must be approved at a shareholders' meeting by more than two-thirds of the votes cast and more than two-thirds of the share capital represented at the meeting. After October 16, 2005, a simple majority will be sufficient to elect a new director, both before and after the expiration of an incumbent's term of office.

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. This date may not be more than 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 ordinary general meetings on four weeks' written notice and extraordinary general meetings on two 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 notice of meetings. 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.

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 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. The board of directors, as required by the articles of association, will refuse to approve any transfer of our shares insofar as such share acquisition may impair any license to acquire real property or other rights held by us or any of our subsidiaries, or our chances of later acquiring such license. We do not presently hold any license or concession which could be impaired by such an acquisition of our shares.

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 further below, 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, which 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 a transfer of shares is subject to approval by our board of directors. The approval cannot be withheld without reasonable grounds. This provision could operate to prevent or impede a change in control of PGS.

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 the underlying shares to be issued to the holder, who transfers them to the transferee. A holder of ADSs may vote their shares by either:

- requesting to be certificated by having the underlying shares transferred to a VPS account in the name of the holder; or

- presenting themselves as a shareholder, providing name and address, and a confirmation from Citibank N.A. as depositary for the ADSs to the effect that they are the beneficial owner of the underlying shares; or

- authorizing Citibank N.A. to vote the ADSs on their 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 and/or rights to shares and of its aggregate holdings of shares and/or rights to shares following the acquisition or disposition if the acquisition or disposition results in its aggregate beneficial ownership of shares and/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 any holder 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 more than two-thirds of the votes cast and more than 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 a preemptive right 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 the 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 United States securities laws. If we decide not to file a registration statement, those U.S. holders will 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; and
- 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.

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 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 the Norwegian courts to 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 a two-thirds majority of the aggregate votes cast by its voting shares and by 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 the 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 matter concerning a loan or other credit to the director or the pledging of security for the director's debt.

Other Provisions Relating to 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 acquiror 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 acquiror 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, 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 shareholders 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 more than two-thirds of the votes cast and more than 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. Such compulsory acquisition would imply that the majority shareholder has become the owner of the acquired shares with immediate effect. On effecting the compulsory acquisition, the majority shareholder would have 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 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.

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, that 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). Several amendments to Norwegian tax law have been proposed in the national budget in Norway for 2005. The proposals include, among others, an exemption from taxation for dividends and gains from disposal of shares for corporate shareholders, although individual shareholders would continue to be subject to taxation of such dividends and gains. The amendments are expected to be enacted during 2004, with some 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 foreign personal holding company, a foreign investment company, or a passive foreign investment company as those terms are 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 Tax Directorate. There is some uncertainty, however, as to whether and when such a refund may be obtained. The proposed amendments to the Norwegian tax law would not affect the withholding tax on dividends distributed to residents of the United States.

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. Under the proposed amendments to the Norwegian tax law, the dividend would be exempted from taxation in Norway if the business activity in Norway is owned by a corporate entity in the United States.

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 tax years beginning after December 31, 2002 through tax 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 a qualifying U.S. stock exchange 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. It is undetermined whether our shares or ADRs will be traded on a qualifying U.S. stock exchange. However, 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 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 stock for more than 60 days during the 121-day period beginning on the date that is 60 days before the date on which the share becomes ex-dividend (disregarding any period during which the U.S. Holder has a diminished risk of loss with respect to such stock), 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, for taxable years beginning after December 31, 2004, 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 within the "financial services income" category will generally be within the "general income" category.

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 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.

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 who is eligible for taxation in Norway are taxable as general income at a flat rate of 28%. Losses are deductible against general income. The tax liability and deductibility apply irrespective of how long the shares have been owned and the number of shares that is sold. The gain or loss is calculated for each individual share as the difference between the consideration received and the tax basis of the share. The tax basis of the share is determined as the acquisition cost, adjusted for annual changes in our taxed equity during the shareholders' ownership period. The calculation of the change in taxed equity is based on taxable profit, reduced by taxes payable and any dividends. 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. Under the proposed amendments to the Norwegian tax law, gains from disposal of shares would be exempted from taxation if the shareholder is a corporate entity. Losses would not be deductible. If the shareholder is an individual, a gain from disposal of shares would be taxable as general income at a flat rate of 28%. The calculation of the taxable gain for the individual would also be amended, whereby the gain would be calculated as the difference between the consideration received and the acquisition cost, adjusted for a "protected yield" (equal to average interest rate on five-year bonds).

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 stock, 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 stock, 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 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, foreign currency exchange rates and crude oil prices, as discussed below.

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. As of December 31, 2003, we had no open interest rate swap or interest rate lock agreements. As a result, our exposure to changes in interest rates results primarily from our short-term and long-term debt with both fixed and floating interest rates, from our capital lease obligations and from our UK leases. The following table presents principal amounts and related average interest rates by year of maturity for our debt obligations as of December 31, 2003:

	2004	2005	2006	2007	2008	Thereafter
			(Dollars in thousands)			
Debt:						
Fixed Rate	$10,200	$10,990	$261,920	$12,900	$14,040	$795,019
Average Interest Rate	8.28%	8.28%	8.01%	8.28%	8.28%	9.89%
Variable Rate	$ 8,312	$ 8,391	$ 1,666	$ 355	$ 354	$ 3,039
Average Interest Rate	3.32%	3.32%	2.93%	2.30%	2.30%	2.30%

As of December 31, 2003, we had capital lease obligations of $89.3 million payable through 2008. Interest associated with these capital lease obligations is based on U.S. dollar LIBOR plus a margin. Accordingly, for every one percentage point change in LIBOR, our interest expense will increase approximately $0.8 million in 2005.

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%. 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. As of December 31, 2003, our balance sheet reflected a liability of $48.6 million for this interest rate exposure. This liability was recorded upon our adoption of fresh start reporting and will be amortized based on future rental payments. During 2003, 2002 and 2001, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $1.5 million, $3.9 million and $1.5 million in the ten months ended October 31, 2003 and the years ended December 31, 2002 and 2001, respectively. 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 19 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 Mexican peso, Bolivian boliviano, Dubi dirham, Bangladesh taka, Kazakhstan tenge, Indian rupee, Saudi Arabian riyal, British pound and the Norwegian kroner 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. As of December 31, 2002 and 2003, we did not have any open forward exchange contracts to manage the exposure related to these risks.

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.

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

Commodity Risk

We operate in the worldwide crude oil markets and are exposed to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2003 (combined) was 4,056,083 barrels, with an average realized price of $29.37 per barrel. In 2002 the average realized price was $27.87 per barrel. At the production level for 2003, an average 10% change in crude oil prices would have a pre-tax effect of approximately $12 million.

As of December 31, 2002 and 2003, we did not have outstanding any derivative commodity instruments. In the first half of 2004, we sold forward 950,000 barrels of our second half production at an estimated average of $30.50 per barrel.

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

Not applicable.

PART II

ITEM 13. *Defaults, Dividend Arrearages and Delinquencies*

We hereby incorporate information called for by this item by reference to our Form 6-Ks filed on July 2, 2003, July 18, 2003, September 11, 2003, October 10, 2003 and November 4, 2003.

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

We hereby incorporate information called for by this item by reference to our Form 6-Ks filed on July 29, 2003, September 11, 2003, October 10, 2003, October 20, 2003, October 21, 2003, November 4, 2003 and November 7, 2003.

ITEM 15. *Controls and Procedures*

Because of the sale of the operations conducted by our Atlantis, Tigris and PGS Production Group Ltd. (formerly Atlantic Power Group) subsidiaries in 2002 and 2003, for purposes of presenting U.S. GAAP consolidated financial statements for the three years ended December 31, 2003, we were required to have our 2001 financial statements re-audited to reflect the businesses sold as discontinued operations. In connection with that re-audit and the audit of our financial statements for 2002 and 2003, we have identified various accounting errors requiring restatement of our historical U.S. GAAP financial statements for 2001. The nature, amounts and impact of these restatements are described in "Operating and Financial Review and Prospects — Restatement of Previously Issued Financial Statements" in Item 5 of this annual report and in note 4 of the notes to our consolidated financial statements included in Item 18 of this annual report.

In planning and performing their audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) of our U.S. GAAP consolidated financial statements for the two months ended December 31, 2003 (Successor), the ten months ended October 31, 2003 (Predecessor) and the years ended December 31, 2002 and 2001 (Predecessor), and as of December 31, 2003 (Successor) and 2002 (Predecessor), our independent auditors, Ernst & Young AS ("EY"), considered our internal controls to determine auditing procedures and noted certain matters involving internal control and its operation that they considered to be reportable conditions under standards established by the American Institute of Certified Public Accountants. EY reported to our Audit Committee material weaknesses regarding various elements of our system of internal controls. They noted weaknesses with respect to our documentation of or adherence to accounting policies and procedures relating to significant financial statement accounts, including the quality of support for accounting books and records, and with respect to the quality of financial reporting and closing of books process at the segment level. Their observations also related to more general matters, including supervision and review control activities within the finance and accounting organization and the adequacy of our U.S. GAAP expertise.

As a result of these material weaknesses and other factors, including our 2003 financial reorganization and Chapter 11 proceeding, we have not until recently been able to prepare consolidated financial statements under U.S. GAAP for 2001 or consolidated financial statements under U.S. GAAP for 2002 and 2003. As a result, we did not file our annual report on Form 20-F for the year ended December 31, 2002 and did not timely file our annual report on Form 20-F for the year ended December 31, 2003. We have, however, been providing financial information for these periods that has been prepared in accordance with Norwegian GAAP.

In connection with issuing their opinion dated June 16, 2004 on our Norwegian GAAP consolidated financial statements for the year ended December 31, 2003, EY reported to our Board of Directors that several of the actions we initiated as a response to the material weaknesses referenced above had not been in effect long enough to give desired results and the quality of the closing process for the 2003 Norwegian GAAP consolidated financial statements demonstrated the need to complete the process of providing further improvements and resources.

Under the direction of our new Audit Committee and Board of Directors, which took office in November 2003 when we emerged from Chapter 11 proceedings, our management has taken action, including the hiring of a new Chief Financial Officer in January 2004, to address the material weakness issues. We have developed and are actively implementing a plan to address the matters identified, including:

- changing the reporting line of segment level finance staff from local operational managers to the Chief Financial Officer;
- hiring new personnel with expertise in U.S. GAAP and U.S. regulations;
- improving overall GAAP expertise throughout the accounting organization;
- upgrading the corporate business controller function;
- reinforcing and improving documentation, supervisory review and reporting procedures;
- implementing standardized procedures manuals and training for our shared accounting services globally;
- reviewing all significant accounting policies and practices, leading to the establishment of new and more precise accounting policies;
- establishing and outsourcing our internal audit function in cooperation with the accounting firm Deloitte & Touche;
- establishing a disclosure committee headed by our Chief Financial Officer and implementing revised disclosure controls and procedures; and
- upgrading to a newer version of our financial accounting and reporting system and implementing that system through all of our businesses.

With respect to new personnel, since our exit from Chapter 11 proceedings in November 2003, we have hired:

- a new U.S. GAAP accounting and reporting officer;
- a new compliance officer, primarily in charge of Sarbanes-Oxley Act implementation and internal audit;
- a new group business controller; and
- additional GAAP trained personnel within our various business segments, including a new financial reporting controller for each of Marine Geophysical, Onshore and Pertra.

In addition, within Marine Geophysical, new additional financial reporting controllers have been employed for each of the two largest regions and our marine acquisition group. In Onshore and in our shared accounting services group, we have increased the number of accounting personnel in key areas.

Acting under the supervision and guidance of our Audit Committee and Board of Directors, these new employees, together with various consultants and contractors, have worked to address our material weaknesses, prepare financial statements in accordance with U.S. GAAP and provide EY with support for its re-audit of our 2001 U.S. GAAP financial statements and its audits of our 2002 and 2003 U.S. GAAP financial statements. We believe that our progress to date in addressing our material weaknesses has been hampered by a combination of factors, including (a) our deteriorating financial condition in late 2002 and early 2003 that led ultimately to our financial reorganization in 2003 through a Chapter 11 proceeding, (b) substantial changes in our accounting and financial reporting personnel preceding and during the Chapter 11 process and (c) the substantial effort, complexity and long period of time associated with finalizing the re-audit and audits of our U.S. GAAP financial statements discussed above, including the application of "fresh start" reporting in accordance with SOP 90-7.

Our management, with the oversight of our Audit Committee and Board of Directors, is committed to remediating the remaining material weaknesses and deficiencies in our internal control over financial reporting as expeditiously as possible. We believe that the actions we have taken have significantly improved the quality of our internal control over financial reporting. As of the date of this annual report, we are in the process of completing some of the actions under the established plan and assessing the effectiveness of actions implemented to date under the plan to identify any appropriate changes or additional activities. We expect the following significant activities will extend into the first quarter of 2005, after which we believe our current plan to address previously identified material weaknesses will be substantially completed and in effect:

- completion of the upgrade and extended application of our financial reporting system and training of system users;
- completion of the improvement of our accounting policies and procedures manual and related training of finance function personnel;
- completion and implementation of service level agreements between our global shared accounting services and business units; and
- completion of improvement of certain procedures related to documentation and work-flow.

After taking these actions, and as we prepare for implementation of the assessment and reporting on internal control over financial reporting under Section 404 of the Sarbanes-Oxley Act of 2002 as described below, our management will reassess the effectiveness of our disclosure controls and procedures and our internal control over financial reporting and assess the adequacy and effectiveness of the remedial actions discussed above. In addition, in connection with their audit of our 2004 financial statements, we expect our independent auditors to perform a similar assessment of the effectiveness of the remedial actions we have taken by year end 2004.

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 controls and procedures as of December 31, 2003, 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, as of December 31, 2003, our disclosure controls and procedures were not 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. In addressing the material weaknesses and deficiencies discussed above, we have significantly expanded our disclosure controls and procedures to include additional procedures and analysis to ensure our disclosure controls and procedures were effective in connection with the preparation of this annual report and the financial statements included herein.

Beginning with the year ending December 31, 2005, 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. The internal control report must contain (1) a statement of management's responsibility for establishing and maintaining adequate internal control over financial reporting for us, (2) a statement identifying the framework used by management to conduct the required evaluation of the effectiveness of our internal control over financial reporting, (3) management's assessment of the effectiveness of our internal control over financial reporting as of the end of our most recent fiscal year, including a statement as to whether or not our internal control over financial reporting is effective, and (4) a statement that our independent auditors have issued an attestation report on management's assessment of our internal control over financial reporting.

As described above, we have made and continue to make significant changes in our internal control over financial reporting, changes which began in late 2003 and have continued into 2004. We expect to continue to make changes in our internal control over financial reporting from time to time during our preparation for compliance with Section 404 of the Sarbanes-Oxley Act. The changes taken to date have materially affected and improved, and we believe these and additional changes we expect to make in the future are reasonably likely to materially affect and improve, our internal control over financial reporting going forward. In addition, these changes have been specifically designed to enable us to timely meet the requirements of Section 404 of the Sarbanes-Oxley Act. Although, as described above, we have introduced additional procedures and analysis to ensure our disclosure controls and procedures were effective in connection with the preparation of this annual report and the financial statements included herein, as of the date of this annual report we have not eliminated all material weaknesses described above.

In addition, as we implement remaining changes in our internal controls and as we prepare to address requirements under the Sarbanes-Oxley Act, we may identify additional deficiencies in our system of internal control over financial reporting that either individually or in the aggregate may represent a material weakness requiring additional remedial efforts.

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, as that term is defined by the New York Stock Exchange.

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 ratification by the Board of Directors) for:

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

Under our pre-approval policy, the Audit Committee is required to preapprove all audit, review or attest engagements and permissible non-audit services to be performed by our independent auditors, 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 2003 were preapproved by the Audit Committee.

Aggregate fees through October 31, 2004 for professional services rendered by EY, including reimbursement of out-of-pocket expenses, related to 2003, 2002 and 2001 were as follows:

	2003	2002	2001
		(In thousands)	
Audit fees(1)	$5,434	$2,228	$6,161
Audit-related fees(2)	114	455	—
Fees for tax services(3)	182	51	—
All other fees(4)	541	540	—
Total	$6,271	$3,274	$6,161

(1) Audit fees consisted of fees for audit and re-audit services, which related to the consolidated audit, quarterly reviews, statutory audits, accounting consultations, subsidiary audits and related matters, and fees for audit of fresh start accounting.

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

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

(4) Other fees consisted 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.

PART III

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-61.

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 Nos. 33-61500 and 333-10856))
2.4	— Indenture dated as of November 5, 2003, among the Company, each of the guarantors named therein and Law Debenture Trust Company of New York, as trustee (the "Trustee")
2.5	— First Supplemental Indenture, dated as of November 5, 2003, among the Company, each of the guarantors named therein and the Trustee
2.6	— Second Supplemental Indenture, dated as of June 4, 2004, among the Company, each of the guarantors named therein and the Trustee

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	— Employment agreement dated November 4, 2002 between the Company and Svein Rennemo (the "Employment Agreement")
4.2	— Addendum to the Employment Agreement dated June 8, 2004 between the Company and Svein Rennemo
4.3	— 2004 CEO Bonus Scheme
8.1	— Subsidiaries (included in Item 4 of the annual report)
11.1	— Code of Conduct
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
15.2	— Remuneration Committee Charter

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: November 16, 2004

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, 2003 (Successor) and 2002 (Predecessor), and the related consolidated statements of operations, changes in shareholders' equity (deficit), and cash flows for the two months ended December 31, 2003 (Successor) and ten months ended October 31, 2003 (Predecessor) and for the years ended December 31, 2002 and 2001 (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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Geo-Services ASA and subsidiaries as of December 31, 2003 (Successor) and 2002 (Predecessor), and the consolidated results of their operations and their cash flows for the two months ended December 31, 2003 (Successor), the ten months ended October 31, 2003 (Predecessor) and the years ended December 31, 2002 and 2001 (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, 2002, the provisions of Statement of Financial Accounting Standards No. 142, *"Goodwill and Other Intangible Assets"* and Statement of Financial Accounting Standards No. 144 *"Accounting for the Impairment or Disposal of Long-Lived Assets"*, and, as of January 1, 2003, the provisions of Statement of Financial Accounting Standards No. 143, *"Accounting for Asset Retirement Obligations."*

As more fully described in Note 4, the 2001 financial statements have been restated to correct certain errors in the application of U.S. generally accepted accounting principles.

ERNST & YOUNG AS

Oslo, Norway
November 12, 2004

CONSOLIDATED BALANCE SHEETS

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars, except share data)	
ASSETS		
Cash and cash equivalents	$ 105,225	$ 91,617
Restricted cash	41,123	21,219
Accounts receivable, net	127,706	169,136
Unbilled and other receivables	47,864	44,510
Deferred tax assets	—	1,193
Other current assets	62,610	52,658
Assets of discontinued operations	—	68,768
Total current assets	384,528	449,101
Multi-client library, net	408,005	583,859
Property and equipment, net	1,060,183	1,702,348
Oil and natural gas assets, net	36,426	37,040
Restricted cash	10,014	10,014
Investments in associated companies	8,070	10,458
Intangible assets, net	52,609	5,337
Other long-lived assets	37,525	41,580
Total assets	$1,997,360	$ 2,839,737
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt and current portion of long-term debt	$ 18,512	$ 1,005,061
Current portion of capital lease obligations	19,963	25,332
Debt and other liabilities of discontinued operations	—	21,523
Accounts payable	56,318	55,514
Accrued expenses	147,336	219,544
Deferred tax liabilities	2,166	—
Income taxes payable	17,946	4,703
Total current liabilities	262,241	1,331,677
Long-term debt	1,108,674	1,320,339
Long-term capital lease obligations	63,473	88,795
Other long-term liabilities	197,663	124,196
Deferred tax liabilities	10,738	24,405
Total liabilities	1,642,789	2,889,412
Commitments and contingencies (Note 19)		
Minority interest in consolidated subsidiaries	937	257
Guaranteed preferred beneficial interest in PGS junior subordinated debt securities	—	142,322
Shareholders' equity (deficit):		
Common stock; 20,000,000 shares authorized, issued and outstanding, par value NOK 30, at December 31, 2003 and 123,345,987 shares authorized, 103,345,987 shares issued and outstanding, par value NOK 5, at December 31, 2002	85,714	71,089
Additional paid-in capital	277,427	1,225,115
Accumulated deficit	(9,953)	(1,458,097)
Accumulated other comprehensive income (loss)	446	(30,361)
Total shareholders' equity (deficit)	353,634	(192,254)
Total liabilities and shareholders' equity	$1,997,360	$ 2,839,737

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

CONSOLIDATED STATEMENTS OF OPERATIONS

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars, except per share and share data)			
Revenues Services	$ 162,827	$ 849,767	$ 1,010,534	$ 893,230
Revenues Products	9,544	112,097	32,697	—
Total Revenues	172,371	961,864	1,043,231	893,230
Cost of sales Services	90,700	454,396	530,386	557,074
Cost of sales Products	6,254	33,382	10,801	—
Depreciation and amortization	55,699	301,576	367,503	336,480
Research and development costs	598	2,024	2,766	3,752
Selling, general and administrative costs	7,366	44,326	53,426	61,999
Impairment of long-lived assets	—	95,011	558,471	12,686
Other operating (income) expense, net	1,052	21,324	8,487	(125,559)
Total operating expenses	161,669	952,039	1,531,840	846,432
Operating profit (loss)	10,702	9,825	(488,609)	46,798
Other income (expense):				
Income (loss) from associated companies	200	774	(11,501)	(690)
Interest expense	(16,870)	(98,957)	(153,301)	(151,624)
Other financial items, net	(4,264)	(1,472)	33,792	(6,269)
	(10,232)	(89,830)	(619,619)	(111,785)
Reorganization items:				
Gain on debt discharge	—	1,253,851	—	—
Fresh-start adoption	—	(532,268)	—	—
Cost of reorganization	(3,325)	(52,334)	(3,616)	—
Minority expense (benefit)	110	570	778	(4)
Income tax expense (benefit)	(3,849)	21,911	185,890	28,344
Income (loss) from continuing operations before cumulative effect of change in accounting principles	(9,818)	556,938	(809,903)	(140,125)
Loss from discontinued operations, net of tax	(135)	(2,282)	(201,137)	(32,354)
Income (loss) before cumulative effect of change in accounting principles	(9,953)	554,656	(1,011,040)	(172,479)
Cumulative effect of change in accounting principles, net of tax	—	2,389	(163,638)	—
Net income (loss)	$ (9,953)	$ 557,045	$ (1,174,678)	$ (172,479)
Basic and diluted income (loss) per share from continuing operations	$ (0.49)	$ 5.39	$ (7.84)	$ (1.36)
Loss from discontinued operations, net of tax	(0.01)	(0.02)	(1.95)	(0.32)
Cumulative effect of change in accounting principle, net of tax	—	0.02	(1.58)	—
Basic and diluted net income (loss) per share	$ (0.50)	$ 5.39	$ (11.37)	$ (1.68)
Weighted average basic and diluted shares outstanding	20,000,000	103,345,987	103,345,987	102,768,283

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	2001
				(Restated)
		(In thousands of dollars)		
Cash flows from operating activities:				
Net income (loss)	$ (9,953)	$ 557,045	$(1,174,678)	$(172,479)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization charged to expense	55,699	301,576	367,503	336,480
Non-cash impairments, loss (gain) sale of subsidiaries and change in accounting principles, net	32	92,622	935,244	(82,537)
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	—	13,152	—	—
Cash effects related to discontinued operations	157	3,185	5,540	(3,274)
Provision for deferred income taxes	(5,801)	(1,918)	171,771	25,702
(Increase) decrease in accounts receivable, net	34,582	6,848	(22,628)	(31,030)
Increase (decrease) in accounts payable	19,391	(18,587)	(10,814)	(1,764)
Loss on sale of assets	—	6,193	11,750	294
Other items	(35,761)	(51,674)	9,319	46,686
Net cash provided by operating activities	58,346	188,676	293,007	118,078
Cash flows (used in) provided by investing activities:				
Investment in multi-client library	(9,461)	(81,142)	(151,590)	(174,028)
Capital expenditures	(15,985)	(42,065)	(56,735)	(147,536)
Capital expenditures on discontinued operations	—	(118)	(77,364)	(54,467)
Sale of subsidiaries	—	50,115	20,222	175,000
Other items, net	357	3,478	(9,030)	(19,485)
Net cash used in investing activities	(25,089)	(69,732)	(274,497)	(220,516)
Cash flows (used in) provided by financing activities:				
Net proceeds — issuance of long-term debt	—	—	—	234,285
Net proceeds — issuance of common stock, including stock option exercises	—	—	—	816
Repayment of long-term debt	(4,850)	(70,496)	(340,809)	(88,694)
Principal payments under capital leases	(3,025)	(22,352)	(19,839)	(11,816)
Net increase (decrease) in bank facility and short-term debt	—	(48)	335,348	(5,667)
Net (payments) receipts under tax equalization swap contracts	—	—	9,566	(64,575)
Net (increase) decrease in restricted cash	3,824	(23,728)	1,602	(7,497)
Other items, net	(17,932)	—	8,098	—
Net cash (used in) provided by financing activities	(21,983)	(116,624)	(6,034)	56,852
Effect of exchange rate changes on cash	—	14	537	(93)
Net increase (decrease) in cash and cash equivalents	11,274	2,334	13,013	(45,679)
Cash and cash equivalents at beginning of period	93,951	91,617	78,604	124,283
Cash and cash equivalents at end of period	$105,225	$ 93,951	$ 91,617	$ 78,604

The accompanying notes are an integral part of these consolidated financial statements.
Supplementary cash flow information is included in note 27.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY (DEFICIT)

	Common Stock				Accumulated other comprehensive income (loss)			
	Number	Par value	Additional paid-in capital	Accumulated deficit	Foreign currency translation adjustments	Pension minimum liability	Accumulated other comprehensive income (loss)	Shareholders' equity
	(In thousands of dollars, except for share data)							
Predecessor Company:								
Balance at December 31, 2000, as restated	102,347,987	$ 70,542	$ 1,215,884	$ (109,863)	$(30,858)	$ —	$(30,858)	$ 1,145,705
Comprehensive loss:								
Net loss				(172,479)	—	—	—	(172,479)
Other comprehensive loss				—	(2,762)	(346)	(3,108)	(3,108)
Total comprehensive loss				(172,479)	(2,762)	(346)	(3,108)	(175,587)
Issuance of common stock	900,000	493	8,558	—	—	—	—	9,051
Exercise of stock options	98,000	54	673				—	727
Balance at December 31, 2001, as restated	103,345,987	71,089	1,225,115	(282,342)	(33,620)	(346)	(33,966)	979,896
Comprehensive income (loss):								
Net loss				(1,174,678)	—	—	—	(1,174,678)
Other comprehensive income (loss)				—	7,195	(3,668)	3,527	3,527
Total comprehensive income (loss)				(1,174,678)	7,195	(3,668)	3,527	(1,171,151)
Dividends to minority interest				(1,077)	78	—	78	(999)
Balance at December 31, 2002	103,345,987	71,089	1,225,115	(1,458,097)	(26,347)	(4,014)	(30,361)	(192,254)
Comprehensive income (loss):								
Net income				557,045	—	—	—	557,045
Other comprehensive income (loss)				—	1,580	(3,230)	(1,650)	(1,650)
Total comprehensive income (loss)				557,045	1,580	(3,230)	(1,650)	555,395
Reorganization items	(103,345,987)	(71,089)	(1,225,115)	901,052	24,767	7,244	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 (loss)				—	446	—	446	446
Total comprehensive income (loss)				(9,953)	446	—	446	(9,507)
Balance at December 31, 2003	20,000,000	$ 85,714	$ 277,427	$ (9,953)	$ 446	$ —	$ 446	$ 353,634

The Company's ability to pay dividends is limited to free equity as defined in Norwegian corporate law and measured on the basis of the unconsolidated financial statements of the parent company, PGS ASA, as prepared in accordance with generally accepted accounting principles in Norway. At December 31, 2003, the Company had no free equity available for payment of dividends to shareholders.

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

NOTES TO 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 (see Note 2 regarding adoption of new accounting requirements which affect the Company's consolidation).

PGS is a technologically focused oilfield services company principally involved in providing geophysical services worldwide and providing floating production services in the North Sea. Globally, it 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 floating production, storage and offloading ("FPSO") vessels. It also owns a small oil and natural gas company that produces oil and natural gas from licenses on the Norwegian Continental Shelf. The Company's headquarters are at Lysaker, Norway.

The Company considers its primary basis of accounting to be US generally accepted accounting principles ("US GAAP"), and has prepared these consolidated financial statements under 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. In 2002 and early 2003, the Company sold certain businesses, which under US GAAP required the Company to restate its previously issued historical financial statements for the year ended December 31, 2001, so that the sold businesses are reported as discontinued operations and not included in income from continuing operations. The Company's previously issued consolidated financial statements for the year ending December 31, 2001 had been audited by an independent accounting firm that has since been dissolved. As a result, PGS was required to have its successor independent auditors "re-audit" its 2001 consolidated financial statements. In connection with its re-audit and the audit of 2002 and 2003, the Company identified various accounting errors requiring further restatements to the previously published historical US GAAP financial statements for the year ended December 31 2001. These errors and restatements are described more fully in Note 4.

On July 29, 2003, PGS ASA filed a voluntary petition for protection under Chapter 11 of the US Bankruptcy Code. The filing was based on a financial restructuring plan that was pre-approved by a majority of the Company's creditors and a group of its largest shareholders. The Company emerged from Chapter 11 on November 5, 2003, and 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

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 will be 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.

Use of Estimates.

The preparation of financial statements in accordance with US 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.

Consolidation and Equity Investments.

The Company prepares its consolidated financial statements in accordance with US GAAP. The consolidated financial statements include Petroleum Geo-Services ASA, its wholly owned and majority-owned subsidiaries that it controls, and variable interest entities for which it is the primary beneficiary. All inter-company transactions and balances have been eliminated in 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. All equity investments for which the equity securities do not have readily determinable fair values and for which the Company does not have the ability to exercise significant influence are accounted for under the cost method.

The Company periodically reviews its investments 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.

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 bid bonds, employee tax withholdings, restricted deposits under contracts, and cash in our wholly owned captive insurance company. During 2003 the Company had increased balances of restricted cash related to bid bonds, which amounted to $27.3 million at December 31, 2003 compared to zero at December 31, 2002.

Foreign Currency Translation.

The Company's reporting currency is the US dollar ("dollar") as it is the functional currency for substantially all of its operations throughout the world.

The financial statements of non-US 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.

The exchange rate between the Norwegian Kroner and dollar at December 31, 2003 and 2002 was NOK 6.79 per dollar and NOK 7.02 per dollar, respectively. The Predecessor recorded $4.3 million, $10.9 million and $1.7 million in net foreign exchange losses, exclusive of the effects of the tax equalization swap contracts (see Note 17), for the ten months ended October 31, 2003 and for the years ended December 31, 2002 and 2001, respectively. The Successor recorded $5.2 in net foreign exchange losses in the two-month period ended December 31, 2003. At November 10, 2004 the exchange rate between the Norwegian Kroner and dollar was NOK 6.30 per dollar.

Operating and Capital Leases.

The Company has significant operating lease arrangements and several capital lease arrangements (mainly for its UK leases (described below) and land seismic equipment). The Company accounts for capital lease arrangements as if it had acquired the assets and correspondingly records as capital lease obligation an amount equal to the lesser of the asset's fair market value or the present value of the future lease payments. The assets are depreciated over their expected useful lives or the related lease terms, whichever is shorter. Depreciation expense associated with assets under capital leases is included with depreciation and amortization of all other assets in the consolidated statement of operations.

UK Leases.

The Company has periodically executed leasing arrangements in the United Kingdom ("UK leases") relating to certain seismic and FPSO vessels and/or equipment. Under the leases, generally, 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. These UK leases provide the Lessors with the tax depreciation rights to the assets and, therefore, the ability to utilize the related tax benefits. Under these UK leases, the Company indemnified the Lessors against certain future events that could reduce their expected after-tax returns. These events include potential changes in UK tax laws and interpretations thereof (including interpretations relating to depreciation rates) and changes in interest rates as the leases are based on assumed interest rates.

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") equal to the basic rentals and termination sum obligations, as defined in 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 Company amortized deferred gains associated with interest rate changes of $1.0 million, $1.4 million and $0.9 million in the ten months ending October 31, 2003 and years ending December 31, 2002 and 2001, respectively, which is reported in other financial items, net. All deferred gains relating to tax contingencies were recognized in the results of operations prior to 2001.

The Defeased Rental Payments are based on assumed Sterling LIBOR rates between 8% and 9% (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"). During 2003, 2002, and 2001, actual interest rates were below the Assumed Interest Rates, and the Company made Additional Required Rental Payments of approximately $1.5 million, $3.9 million, and $1.5 million, in the ten months ending October 31, 2003, and years ending December 31, 2002 and 2001, respectively, which was expensed as incurred and reported in 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% discount rate. This liability amounted to 30.5 million British Pounds Sterling (approximately $51.6 million) at November 1, 2003, and was amortized to $27.4 million British Pounds Sterling ($48.6 million) at December 31, 2003.

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.

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. 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, PGS no longer capitalizes such costs.

The investment in the multi-client library is recorded in a manner consistent with the 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 as well as past experience. These expectations include consideration of geographic location, prospects, political risk, exploration license periods and general economic conditions. The local sales and operating management estimate, 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. Subsequent to the adoption of fresh start reporting, for purposes of streamlining the accounting method of amortization, the Company has categorized its multi-client surveys into three amortization categories with amortization rates 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 estimate. Each category therefore includes surveys where remaining book value as a percentage of remaining estimated sales is less than or equal to the amortization rate applicable to each 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 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 book value allowed for each survey or group of surveys in the multi-client library.

Subsequent to the 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. With the adoption of fresh start reporting, 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:

Calendar year	Successor Company % of total cost 5-year profile	Successor Company % of total cost 3-year profile	Predecessor Company % of total cost Marine components (excluding Brazil)	Predecessor Company % of total cost Marine components (Brazil)	Predecessor Company % of total cost 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%	

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, 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.

Oil and Natural Gas Assets.

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 to be non-productive, the drilling and equipment costs for the well are expensed 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. 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.

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.

Goodwill.

The Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *"Goodwill and Other Intangible Assets"* ("SFAS 142") as of January 1, 2002. Under SFAS 142, goodwill and intangible assets acquired in a purchase business combination and determined to have an indefinite useful life are not amortized, but instead tested for impairment at least annually in accordance with the provisions of SFAS 142. SFAS 142 also requires that intangible assets with finite useful lives be amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, *"Accounting for the Impairment or Disposal of Long-Lived Assets"* ("SFAS 144").

In connection with SFAS 142's transitional goodwill impairment evaluation, the Company was required to perform an assessment of whether there was an indication that goodwill was impaired as of the date of adoption. To accomplish this, the Company identified its reporting units and determined the carrying value of each reporting unit by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units as of January 1, 2002, which included Marine Geophysical, Onshore, Production, Atlantic Power (Production Services) and the reservoir consultant activities. The Company was required to determine the fair value of each reporting unit and compare it to the carrying amount of the reporting unit. To the extent the carrying amount of a reporting unit exceeded the fair value of the reporting unit, the Company would be required to perform the second step of the transitional impairment test, which would require the Company to compare the implied fair value of the reporting unit goodwill with the carrying amount of the reporting unit goodwill. As of January 1, 2002, the second step was required to be performed for the Company's Production and reservoir consultants units as the implied fair value of the Company's reporting units exceeded their respective carrying amounts. This resulted in a goodwill impairment charge of $163.6 million upon adoption of SFAS 142 of which $161.1 million and $2.5 million related to the production and reservoir reporting units respectively.

In September 2002, the Company performed a similar test to that described above, for its Marine Geophysical reporting unit due to identified impairment factors, which included a significant reduction in the market value of the Company. This resulted in a goodwill impairment charge of $9.4 million (see Note 5).

Intangible Assets.

Intangible assets other than goodwill generally relate to direct costs of software product development, patents, royalties and licenses. In addition several intangible assets were recognized as a consequence of the Company's adoption of fresh start reporting. Such intangible assets include favorable contracts, order backlog and the value of various existing technologies used in the Company's operations. Intangible assets are stated at cost less accumulated amortization and any impairment charges. Amortization is calculated on a straight-line basis over estimated period of benefit, ranging from one to 10 years.

Other Long-Lived Assets.

Other long-lived assets consist of debt issue costs, long-term receivables, and prepaid pension cost. Debt issue costs relating to long-term debt are included in interest expense using the effective interest method over the period the associated loans are outstanding.

Impairment of Long-Lived Assets.

Effective January 1, 2002, the Company adopted SFAS 144 which provides guidance for evaluating the recoverability of all long-lived assets, principally property, plant and equipment and definite-lived intangible assets. SFAS 144 provides similar guidance to Statement of Financial Accounting Standards No. 121, "*Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed of*" ("SFAS 121"), which was applied prior to January 1, 2002. SFAS 144 requires that long-lived assets (or the group of assets, including the asset in question, that represents the lowest level of separately identifiable cash flows) be evaluated whenever events or changes in circumstances indicate that the carrying amount of assets or cash generating units may not be recoverable. The Company reviews 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 groups of assets. Long-lived assets (multi-client library, property and equipment and oil and natural gas assets accounted for under the successful efforts method) are 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. Prior to the adoption of fresh-start reporting, oil and natural gas assets were assessed for impairment in accordance with the full cost accounting guidelines as described under "Oil and Natural Gas Assets" above.

Steaming and Mobilization.

Subsequent to the adoption of fresh start reporting, costs incurred while moving 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 Company (Predecessor) capitalized a proportionate share of cost incurred while moving or "steaming" a seismic vessel or crew as part of the cost of multi-client surveys.

Derivative Financial Instruments.

On January 1, 2001, the Company adopted Statement of Financial Accounting Standards 133, *"Accounting for Derivative Instruments and Hedging Activities, as amended"* ("SFAS 133"). Under SFAS 133, all derivative instruments are recognized in the balance sheet at their fair values while realized and unrealized gains and losses attributable to derivative instruments that do not qualify for hedge accounting are recognized in income as they arise. To qualify for hedge accounting, the details of the hedging relationship must be formally documented at inception of the arrangement, including the risk management objective, hedging strategy, hedged items, specific risks that are being hedged, the derivative instrument and how effectiveness is being assessed. There are three types of hedges: cash flow hedges, which are hedges that use derivatives to offset the variability of expected future cash flow, fair value hedges, which are hedges that eliminate the risk of changes in the fair value of assets, liabilities and certain firm commitments, and net investment hedges, which hedge foreign currency exposure of a net investment in a foreign operation. The adoption of SFAS 133 did not have any material impact on the Company's financial position or results of operations.

The Company uses derivative financial instruments periodically to manage exposure to changes in foreign currency exchange rates, changes in interest rates on variable rate debt, and firm commitments or expected future cash flows associated with the purchases of property, plant and equipment. The Company may also use derivatives to manage exposure to commodity price fluctuations for oil and natural gas. The Company does not engage in derivative financial instrument transactions for speculative purposes. As of December 31, 2003 and 2002, the Company did not have outstanding any derivative financial instruments that qualified for hedge accounting.

During 1998 and 1999, the Company entered into forward foreign currency exchange contracts known as tax equalization swaps ("TES") related to its senior unsecured notes, its Oslo Seismic mortgage notes and its trust preferred securities. These contracts hedge the risk related to the cash tax effect of unrealized exchange rate fluctuations between the Norwegian Kroner and the US dollar related to the Company's US dollar-denominated debt and trust preferred securities, where such foreign currency exchange gains and losses are taxable and deductible for Norwegian statutory tax purposes. In 2002, all outstanding TES contracts were terminated and the Company received $21.0 million from the counter-party as the termination settlement, which resulted in a gain of $45.3 million. The changes in fair value (including accruals for cash payments and realized and unrealized gains and losses) of the TES for the years ending December 31, 2002 and 2001 were $45.3 million and ($9.1) million, respectively, exclusive of any tax effects and are recorded in other financial items, net.

Share Based Compensation Plans.

The Company applies the intrinsic value method in accordance with Accounting Principles Board ("APB") Opinion 25, *"Accounting for Stock Issued to Employees,"* in accounting for its share-based compensation plans and has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, *"Accounting for Stock-Based Compensation"* ("SFAS 123"), as amended by SFAS No. 148, *"Accounting for Stock-Based Compensation — Transition and Disclosure".* Accordingly, no compensation cost is recognized under these plans since the option exercise price is above or equal to market value of the stock at measurement date. The Company discloses the amount the compensation cost would have been had the share-based compensation been determined and recognized based on fair values of options awarded.

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:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December, 2002	2001
		(In thousands of dollars)		(Restated)
Net income (loss), as reported	$(9,953)	$557,045	$(1,174,678)	$(172,479)
Deduct: Total share-based compensation expense determined under the fair value based method for all awards, net of related tax effect	—	(5,105)	(9,804)	(10,630)
Pro forma, net income (loss)	$(9,953)	$551,940	$(1,184,482)	$(183,109)
Net income (loss) per share:				
Basic and diluted — as reported	$ (0.50)	$ 5.39	$ (11.37)	$ (1.68)
Basic and diluted — pro forma	$ (0.50)	$ 5.34	$ (11.46)	$ (1.78)

The Company did not grant any share option awards during 2003 or 2002. For share options awards granted during 2001, the fair value of each option award on the grant date was estimated using the Black-Scholes option-pricing model with the following weighted average assumptions: expected volatility of 55%; risk-free interest rate of 4.23%; and expected life of 3.4 years. Dividend yield was assumed to be zero.

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 collectibility is reasonably assured. The Company defers the unearned component of payments received from customers for which the revenue recognition requirements have not been met. On July 1, 2003, the Company adopted the provisions of EITF 00-21, *"Revenue Arrangement with Multiple Deliverables".* Consideration is allocated among the separate units of accounting based on their relative fair values. The adoption of EITF 00-21 did not have a material impact on the Company's financial position or results of operations for the ten-month period ended October 31, 2003 or the two-month period ended December 31, 2003. The Company's revenue recognition policy is described in more detail below.

1. Geophysical Services (Marine and Onshore)

(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 been granted 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 ratable portion 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

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

3. 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.

Capitalization of costs associated with a revenue contract is limited to the deferred revenue related to the contract. In the Consolidated Statements of Operations reimbursements received for expenses incurred under a contract are characterized as revenue in line 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.

Asset Retirement Obligations.

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, "*Accounting for Asset Retirement Obligations*" ("SFAS 143"). SFAS 143 requires entities to record the fair value of an asset retirement obligation ("ARO") 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 entity 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 ARO may result from changes in the assumptions used to estimate the cash flows required to settle the ARO.

The Company has asset retirement obligations associated with its oil and gas producing activities in the Norwegian North Sea and with the sub-sea production facility associated with its *Ramform Banff* FPSO also 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. For oil and natural gas production facilities, the obligations are generally statutory as well as contractual. The asset retirement obligations will be reduced by grants from the Norwegian government, and with contractual payments from FPSO contract counterparts. These receivables have been included in the balance sheet under long-term receivables.

If the accounting change we implemented during 2003 for asset retirement obligations had been effective in 2002 and 2001, the impact on income before cumulative effect of changes in accounting principles and earnings per share would have been immaterial for all periods presented. Computed on a pro forma basis as if SFAS 143 had been applied during all periods presented, the asset retirement obligation would have been $59.0 million and $20.7 million as of January 1, 2003, and January 1, 2002, respectively.

Upon adoption of SFAS 143 on January 1, 2003, the Company recorded $2.4 million (net of taxes) as income from cumulative effect of changes in accounting principles. Application of this new accounting principle resulted in an increase in property, plant and equipment of $6.5 million, an increase in the recorded asset retirement obligation liability of $1.5 million, and a decrease in the recorded long-term receivables of $2.6 million.

The following table presents the movements in ARO for the ten months ending October 31, 2003, and the two months ending December 31, 2003:

	Successor Company	**Predecessor Company**
Asset retirement obligation	**Two months ended December 31, 2003**	**Ten months ended October 31, 2003**
	(In thousands of dollars)	
Balance at beginning of period	$49,847	$59,767
Accretion expense	599	3,793
Liabilities settled in the period	(430)	—
Revision in estimated cash flow/fair value	—	(13,713)
Balance at end of period	$50,016	$49,847

Governmental grants and contractual receivables related to the asset retirement obligation are included in other long-lived assets with $16.8 million at December 31, 2003 and $17.2 million at December 31, 2002.

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 addresses 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 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. By December 31, 2003 Walter Herwig AS was a 100% owned subsidiary of the Company. 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 in relation to FIN 46R. Based on the characteristics of the lessor entities, the Company has determined that the entities are likely to be VIEs. 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.

However, based on information received from the lessor entities, which are all multi-lessee entities, the debt issued to finance the activities of the entities is full recourse to all assets of each entity. Based on publicly available information and confirmations from the lessor entities, the Company has determined that its relative portions of the fair value of the assets of the lessor entities are less than 50% of the assets of each entity. Accordingly, the Company has determined that it is not the primary beneficiary of these lessor entities and that the UK leases are not separate silos within the lessor entities (separate VIEs).

The Company has certain contingent obligations under its UK leases the maximum amount of which is not determinable. See note 19 for further discussion of these contingent liabilities.

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. In connection with the adoption of fresh start reporting, contingencies were recorded at their estimated fair values even if they were not considered probable.

Pro forma information.

As described above the Company adopted the provisions of SFAS 142, effective January 1, 2002 and SFAS 143, effective January 1, 2003. The pro forma effects of these changes in accounting for preceding years are shown in the table below:

	Loss from continuing operations before cumulative effect of change in accounting principles		Income (loss) before cumulative effect of change in accounting principle		Net income (loss)	
	2002	2001 (Restated)	2002	2001 (Restated)	2002	2001 (Restated)
	(In thousands of dollars, except per share data)					
Reported income (loss)	$(809,903)	$(140,125)	$(1,011,040)	$(172,479)	$(1,174,678)	$(172,479)
Add back goodwill amortization	—	5,162	—	6,390	—	6,390
Asset removal obligation pro forma effect	362	792	362	792	362	792
Reverse cumulative effect of change in accounting principle	—	—	—	—	163,638	—
Pro forma income (loss)	$(809,541)	$(134,171)	$(1,010,678)	$(165,297)	$(1,010,678)	$(165,297)
Pro forma income (loss) per share (basic and diluted)	$ (7.83)	$ (1.31)	$ (9.78)	$ (1.61)	$ (9.78)	$ (1.61)

NOTE 3 — 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. In early 2003, the Company was also in violation of certain financial and other covenants of various bank credit and leasing agreements, and as such, had been seeking waivers of these defaults. These circumstances were largely the result of over investing in marine geophysical capacity, as well as excess investments in the late 1990's, financed with substantial amounts of debt, in the *Ramform Banff* FPSO, Atlantis (an oil and natural gas subsidiary) and the multi-client data library, and subsequent underperformance by these assets. 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.

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 10% senior unsecured notes due 2010;
- $250 million of 8% senior unsecured 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 in cash distributed by PGS, 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 per share, 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 (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 a reorganization value as an enterprise value in the range of $1.3 and $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.

This value was determined using various valuation methods including: (i) publicly traded company analysis; (ii) discounted cash flow analysis; and (iii) precedent transactions analysis as follows:

(i) Market values and trading multiples of selected publicly held companies in comparable lines of business were analyzed (FPSO and Geophysical businesses). The enterprise values of the selected companies were calculated as a multiple of certain historical and projected financial data of such companies. These multiples were compared with multiples derived by assigning a range of enterprise values for the corresponding projected financial data of the applicable business of the reorganized PGS.

(ii) A discounted cash flow analysis was performed for each of the business segments, incorporating assumptions for the allocation of corporate and other costs to each business, to estimate the present value of each business' future unlevered, after-tax cash flows based on the financial projections. This was calculated as the sum of the present value of its cash flows through 2010 and the present value of its terminal value as of 2010.

In addition, a discounted cash flow analysis on each of the main assets was performed to estimate the present value of future unlevered, after-tax cash flows for each of the primary assets based on financial projections extending until the end of the useful life of each of the primary assets, ascribing no further residual or terminal value. The negative present value of corporate and other costs was separately valued with a similar approach. A range of discount rates was used to arrive at a range of present values for each asset. These present values were aggregated to arrive at a range of sum of the parts present value.

(iii) Selected recently completed or announced transactions at the time of reorganization with relevance to the Company were reviewed. Enterprise values were calculated using the transactions as multiples of certain historical financial data of such companies. These multiples were compared to multiples derived by assigning a range of enterprise values to the applicable business segment of the Company and dividing those enterprise values by the corresponding historical financial data of the applicable segment of the Company.

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. The assumptions used in the calculations for the discounted cash flow analysis were provided by management based on their best estimate at the time the analysis was performed. These estimates and assumptions are subject to uncertainties and contingencies beyond the Company's control. 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 sheet as of December 31, 2003 and the statements of operations and cash flow for 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 statements of operations and cash flows for the years ended December 31, 2001 and 2002 and for the ten months ended October 31, 2003, and the consolidated balance sheet as of December 31, 2002 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, 2003 and for the two-month period then ended and will have a material impact on consolidated statements of operations for periods subsequent to December 31, 2003. Consequently, the financial information for the Successor and Predecessor companies is 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 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:

PGS ASA Plan of Reorganization Recovery analysis	Predecessor Company	Elimination of debt and equity	Recovery: Surviving debt	Recovery: Cash	Recovery: 2010 note	Recovery: 2006 note	Recovery: Term loan facility	Recovery: Common Stock %	Recovery: Common Stock Value	Recovery: Total Recovery %	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 were 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 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 20). 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.

The following table summarizes the reconciliation of the Predecessor Company's consolidated balance sheet, as of October 31, 2003, to that of the Successor Company's opening balance sheet as of November 1, 2003, giving effect to the emergence from Chapter 11 reorganization and the adoption of fresh-start reporting:

	October 31, 2003	November 1, 2003		
	Predecessor Company	Effects of plan	Fresh start valuation	Successor Company
	(In thousands of dollars)			
ASSETS				
Cash and cash equivalents	$ 93,951	$ —	$ —	$ 93,951
Restricted cash	44,947	—	—	44,947
Accountants receivable, net	162,288	—	2,000	164,288
Unbilled and other receivables	30,771	—	—	30,771
Other current assets	57,625	—	(2,405)	55,220
Assets of discontinued operations	2,753	—	—	2,753
Total current assets	392,335		(405)	391,930
Multi-client library, net	437,732	—	(7,151)	430,581
Property and equipment, net	1,577,065	—	(507,968)	1,069,097
Oil and natural gas assets, net	23,345	—	574	23,919
Restricted cash	10,014	—	—	10,014
Investments in associated companies	9,246	—	(205)	9,041
Intangible assets, net	3,636	—	52,383	56,019
Other long-lived assets	31,102	—	7,601	38,703
Total assets	$2,484,475	$ —	$(455,171)	$2,029,304
LIABILITIES AND SHAREHOLDERS' EQUITY				
Short-term debt and current portion of long-term debt	$2,294,995	$(2,283,395)	$ —	$ 11,600
Current portion of capital lease obligations	19,561	—	—	19,561
Debt and other liabilities of discontinued operations	1,252	—	—	1,252
Accounts payable	36,927	—	—	36,927
Accrued expenses	152,228	29,139	(4,818)	176,549
Income taxes payable	22,570	—	—	22,570
Total current liabilities	2,527,533	(2,254,256)	(4,818)	268,459
Long-term debt	108,015	1,000,405	—	1,108,420
Capital lease obligations	70,352	—	—	70,352
Other long-term liabilities	115,095	—	83,732	198,827
Deferred tax liabilities	21,095	—	(1,817)	19,278
Total liabilities	2,842,090	(1,253,851)	77,097	1,665,336
Minority interest in consolidated subsidiaries	827	—	—	827
Shareholders' equity:				
Common stock	71,089	14,625	—	85,714
Additional paid-in capital	—	809,695	(532,268)	277,427
Retained earnings (deficit)	(397,520)	397,520	—	—
Accumulated other comprehensive income (loss)	(32,011)	32,011	—	—
Total shareholders' equity (deficit)	(358,442)	1,253,851	(532,268)	363,141
Total liabilities and shareholders' equity	$2,484,475	$ —	$(455,171)	$2,029,304

NOTE 4 — Restatement of 2001 Financial Statements

In preparing the 2003 and 2002 financial statements and in the course of the re-audit of the 2001 financial statements, accounting errors were identified that related to previously filed financial statements. As a result, the Company has restated its consolidated balance sheet as of December 31, 2001, and consolidated statements of operations, cash flows and changes in shareholders' equity for the year ended December 31, 2001. The restatements also affected periods prior to 2001. The impact of the restatement on such prior periods was reflected as an adjustment to retained earnings as of January 1, 2001. The restatements (i) correct certain of the Company's historical accounting policies to conform to US GAAP and (ii) correct certain errors made in the application of US GAAP; both of which are "errors" within the meaning of APB Opinion No. 20, *"Accounting Changes."* Set forth below are the restatement adjustments for the year ended December 31, 2001.

Revenue Recognition.

The Company's revenue recognition policy is based on the guidelines in Staff Accounting Bulletin No. 101, *"Revenue Recognition in Financial Statements,"* as described in Note 2, which was in effect for the Company's financial statements for years ended December 31, 2000 and later years. However, certain errors were identified in the application of the accounting policy relating to revenue recognition. These errors primarily related to the recognition of revenue prior to: a) obtaining persuasive evidence of an arrangement as certain amounts were recorded as revenue prior to receiving signatures on final agreements or obtaining written agreements, and/or b) obtaining sales prices that were fixed or determinable as the agreed upon price was not final. Restatement entries were made to reverse the recognized revenue and related cost of sales on these transactions. In addition, revenues in 2001 were restated to recognize revenues from previous years that had been recognized prematurely and restated in the 2001 opening balance.

Accounting for Multi-Client Library.

The Company incurs acquisition costs in the course of self-constructing its multi client library assets which are capitalized pursuant to US GAAP. Errors were determined to have occurred in capitalizing certain general and administrative costs, sales commissions, project management costs, data management costs and technology costs. The Company did not maintain consistent adequate detailed documentation to distinguish between the costs incurred associated with the creation of the asset and the costs associated with selling and administrative efforts. The restatements to the multi-client library acquisition cost also affected capitalized interest, amortization expense and impairments as a consequence of adjusted acquisition cost. Impairments in periods prior to 2001 were recorded based on undiscounted cash flows. This has been restated in the opening retained earnings balance.

Accounting for FPSOs.

The Company re-evaluated costs that were capitalized in connection with upgrade and repair projects on the *Ramform Banff* and *Petrojarl I* FPSO vessels that were completed during 2000 and 2001. As a result, expenditures were identified that should have been included as operating costs as they did not increase the useful life or capacity of the vessels. The effects of these restatements were adjustments to retained earnings in the opening balance, the carrying value of each vessel and related operating and depreciation expenses.

The Company re-evaluated an impairment charge of the subsea assets related to the Banff field reflected in retained earnings at January 1, 2001. The Company determined that the impairment charge resulted from an improper application of US GAAP as cash flows are not separately identifiable. As a result, the impairment charge of $31.6 million was reversed; thereby, increasing retained earnings and the carrying value of property and equipment at January 1, 2001.

Certain of the Company's FPSOs were depreciated using a "modified-units-of-production" method. The Company determined that the straight-line method should have been used from the time the assets were placed in service. As a result, the cumulative effect of this restatement was adjusted to the opening retained earnings balance and depreciation expense for the year ended December 31, 2001 was restated.

The Company depreciates its FPSOs based on cost less salvage value. An error was identified in the amounts of salvage values historically used by the Company for all four FPSOs as it was determined such salvage values were overstated at January 1, 2001. As a result, the salvage values were reduced prospectively from January 1, 2001, and depreciation expense for the year ended December 31, 2001 was restated.

Asset Retirement Obligation for Banff Field.

The Company determined that an asset retirement obligation and a related contractual receivable due from the operator should have been recognized separately in the balance sheet at inception of the contract in January 1999. Originally, the Company recorded none of these. The effect of this restatement is that the value of the receivable will be recognized as other long-lived assets and the asset retirement obligation in other long-term liabilities accreted based on production over the lifetime of the field, which started in January 1999. The accumulated effect is restated in the 2001 opening retained earnings balance, while the build-up of the liability for the year ended December 31, 2001 is charged to net income.

Contract Loss Accruals.

The Company determined that contract loss accruals for service contracts recorded prior to 2001, and partly released into earnings in the year ending December 31, 2001, did not have support under US GAAP, except when SOP 81-1, *"Accounting for Performance of Construction Type and Certain Production Type Contracts"* is used, or the Company has committed to exit the contracts. The effect of this restatement was an adjustment to the opening retained earnings balance and the balance sheet for the year ended December 31, 2001, and a reduction in net income for the year ended December 31, 2001.

Lease Accounting.

The Company identified errors associated with four leases that were originally accounted for as operating leases prior to 2001. A lease for Onshore seismic equipment was determined to be appropriately accounted for as an operating lease, but a substantial penalty for early termination had not been accrued through lease expense in accordance with US GAAP. Three other leases for accounting software, a seismic vessel and a new seismic vessel engine were determined to be inappropriately accounted for as operating leases, and a restatement was recorded to reclassify the leases as capital leases. The restatements affected the 2001 opening retained earnings balance. In addition, the restatements affected lease expense (generally included in selling, general and administrative costs or cost of sales), depreciation, interest expense, capitalized costs and capital lease obligations for the year ended December 31, 2001.

Ceiling Test for Oil and Natural Gas Assets.

The Company determined that a full cost ceiling test under the provisions of SEC full cost accounting should have been performed for the oil and natural gas assets owned by its subsidiary Atlantis for the year ended December 31, 2001. Current management is not able to find any evidence that such a test was carried out. On this basis, a retroactive full cost ceiling test has been performed and an impairment of the oil and natural gas assets for the year ended December 31, 2001 was recognized.

UK Leases.

The Company determined that the UK leases (Notes 2 and 19) were incorrectly recorded and presented in its previously issued financial statements. In prior years' financial statements, all gains were recognized under all these lease transactions. Embedded in these gains were liabilities related to the difference between the projected future distribution from the defeasance banks at inception of the lease and the projected lease payments, based on forward interest rate curves. This element should have been separated from the total gain, recorded as a deferred gain and reduced the recognized gain. The deferred gain related to the interest rate differential should have been amortized over the term of the lease. In the previously issued financial statements, no such gain deferrals were recorded. The restatements reduced the January 1, 2001 opening retained earnings balance. In addition, the restatements affected other financial items for the year ended December 31, 2001.

One of the vessels on such lease was acquired through the acquisition of Awilco Floating Production AS in 1998. As a result, the restatements related to the deferred gain also affected the goodwill in the 2001 opening balance sheet. In addition, the remaining part of the deferred gain relating to the vessel acquired from Awilco Floating Production AS was recognized in the 2000 net income. However, as this was a deferred gain relating to a tax contingency, it should have been recorded as an adjustment of goodwill. The 2001 opening balance in retained earnings has been restated accordingly. In addition, the restatements affected goodwill amortization for the year ended December 31, 2001.

Securitization of Multi-Client Library.

The Company determined that the securitization transaction related to the sale of a portion of its multi-client marine seismic library to a bankruptcy remote, special purpose entity incorporated in Jersey in April 2001 was incorrectly classified in the previously issued financial statements. The special purpose entity should have been consolidated in the Company's financial statements for the year ended December 31, 2001. The adjustment affected the balance sheet for the year ended December 31, 2001 with a reclassification from preferred securities to short term debt. In addition, a reclassification was recorded in the 2001 statement of operations from minority interest expense to financial expenses and selling, general and administrative expenses.

Taxes.

The Company determined that several restatements were necessary to properly reflect deferred and payable taxes, including tax contingencies, in the 2001 opening retained earnings balance and in the consolidated financial statements for the year ended December 31, 2001. This relates to adjustments for errors in the calculation of the originally reported taxes and to tax effects of the other restatements.

Other Adjustments.

The Company identified and recorded several other restatements that affected various captions in the statement of operations for the year ended December 31, 2001 and in the 2001 opening retained earnings balance. The most significant issues affecting the 2001 opening retained earnings balance and/or net income for the year ended December 31, 2001 were as follows:

- Restatements related to the correction of errors resulting from inappropriate cost capitalization and deferral of steaming, mobilization and yard stay costs both in the Marine Geophysical and the Onshore segments.

- Restatements related to the correction of errors resulting from lack of accruals for social security taxes owed for crew-members on certain seismic vessels.

- Restatements related to a number of erroneous accounting entries for several years prior to and including the year ended December 31, 2001, associated with a consolidated subsidiary.

- Restatements related to the correction of an error in the fair value recognized for the TES contracts for the year ended December 31, 2001.

- Restatements related to the recognition of a liability related to a settlement agreement with a customer in 2000. The restatement related to the loss accrual is recorded in the 2001 opening balance instead of in the 2001 statement of operations.

Following is a presentation of the effects of the restatements described above on the January 1, 2001 opening retained earnings balance and net income (loss) for the year ended December 31, 2001:

	Retained earnings as of January 1, 2001	Net income (loss) Year ended December 31, 2001
	(In thousands of dollars)	
As Reported	$ 94,410	$ 4,453
Restatements:		
Revenue recognition	(25,297)	(2,697)
Multi-client library (cost capitalization, impairment and amortization)	(100,214)	(37,649)
FPSOs (cost capitalization, impairment and depreciation)	(59,981)	(63,674)
Asset retirement obligation for Banff field	(7,060)	(3,356)
Contract loss accruals	40,132	(31,532)
Lease accounting	(4,980)	(23,269)
Ceiling test for oil and natural gas assets	—	(20,817)
UK leases	(41,202)	1,163
Taxes	53,825	3,208
Other adjustments:		
Cost capitalization steaming, mobilization and yard stay	(8,173)	(11,493)
Accrued social security taxes	(6,371)	(1,688)
Errors in consolidated subsidiary	(11,542)	3,351
Fair value of TES contracts	—	8,885
Settlement agreement with customer	(5,000)	5,000
Various	(28,410)	(2,364)
As Restated	$(109,863)	$(172,479)

Following are the restated consolidated financial statements compared to financial statements as reported (includes effect of changed presentation due to discontinued operations):

Consolidated Statement of Operations

	Year ended December 31, 2001	
	As restated	As reported
	(In thousands of dollars, except per share data)	
Revenues Services	$ 893,230	$1,052,628
Revenues Products	—	—
Total Revenues	893,230	1,052,628
Cost of sales Services	557,074	535,999
Cost of sales Products	—	—
Depreciation and amortization	336,480	334,506
Research and development costs	3,752	3,752
Selling, general and administrative costs	61,999	78,305
Impairment of long-lived assets	12,686	13,155
Other operating (income) expense	(125,559)	(119,067)
Total operating expenses	846,432	846,650
Operating profit	46,798	205,978
Other income (expense):		
Loss from associated companies	(690)	(491)
Interest expense	(151,624)	(143,179)
Other financial items, net	(6,269)	(22,052)
Income (loss) from continuing operations before minority interest, income taxes and discontinued operations	(111,785)	40,256
Minority expense (benefit)	(4)	—
Income tax expense	28,344	35,803
Income (loss) from continuing operations	(140,125)	4,453
Loss from discontinued operations, net of tax	(32,354)	—
Net income (loss)	$(172,479)	$ 4,453
Basic and diluted income (loss) per share from continuing operations	$ (1.36)	$ 0.04
Discontinued operations	(0.32)	—
Basic and diluted net income (loss) per share	$ (1.68)	$ 0.04

Consolidated Balance Sheet

	December 31, 2001	
	As restated	As reported
	(In thousands of dollars)	
ASSETS		
Cash and cash equivalents	$ 78,604	$ 94,062
Restricted cash	22,821	7,965
Accounts receivable, net	146,508	147,867
Unbilled and other receivables	43,488	85,638
Other current assets	74,647	96,813
Assets of discontinued operations	242,997	250,521
Total current assets	609,065	682,866
Multi-client library, net	799,062	918,072
Property and equipment, net	2,171,443	2,281,105
Restricted cash	10,014	—
Investments in associated companies	13,316	20,713
Deferred tax assets	139,171	170,863
Goodwill and intangible assets, net	173,038	195,654
Other long-lived assets	47,020	33,533
Total assets	$3,962,129	$4,302,806
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt and current portion of long-term debt	$ 400,086	$ 236,498
Current portion of capital lease obligations	14,275	9,931
Debt and other liabilities of discontinued operations	63,045	57,208
Accounts payable	66,328	67,012
Accrued expenses	232,144	206,756
Income taxes payable	2,956	16,448
Total current liabilities	778,834	593,853
Long-term debt	1,913,585	1,903,571
Capital lease obligations	51,303	41,683
Other long-term liabilities	79,975	24,161
Deferred tax liabilities	16,434	73,503
Total liabilities	2,840,131	2,636,771
Commitments and contingencies:		
Minority interest in consolidated subsidiaries	1,101	—
Guaranteed preferred beneficial interest in PGS junior subordinated debt securities	141,000	141,000
Mandatorily redeemable cumulative preferred stock related to multi-client securitization	—	163,588
Shareholders' equity:		
Common stock	71,089	71,089
Additional paid-in capital	1,225,115	1,225,115
Retained earnings (deficit)	(282,342)	98,863
Other comprehensive income (loss)	(33,966)	(33,620)
Total shareholders' equity	979,896	1,361,447
Total liabilities and shareholders' equity	$3,962,129	$4,302,806

Certain amounts have been reclassified to conform to the current balance sheet presentation.

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

Impairments of long-lived assets consist of the following:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Multi-client library	$ —	$90,053	$200,393	$12,686
Production assets and equipment	—	328	331,971	—
Seismic assets and equipment	—	3,539	16,706	—
Other long-lived assets	—	1,091	9,401	—
Total	$ —	$95,011	$558,471	$12,686

SFAS 121 was the applicable guidance for evaluating goodwill and long-lived assets for impairment for 2001. In 2002 and 2003, impairment analyses for long-lived assets were completed in accordance with SFAS 144 and for goodwill in accordance with SFAS 142.

Over the last three years, the Company's sales estimates for several of its multi-client surveys have been revised downwards, resulting in impairments of such surveys in 2001, 2002 and 2003. In 2002 the Company recorded an impairment charge of $332.0 million relating to the FPSO *Ramform Banff* as a result of negative development of the Banff field and decreased prospects for the redeployment of the vessel to more profitable projects. Also in 2002, the Company recorded $9.4 million (included in other long-lived assets above) of impairment of goodwill in relation to its Marine Geophysical segment.

In addition to impairments specified above, the Company adopted the provisions of SFAS 142 on January 1, 2002 and recorded a $163.6 million impairment of existing goodwill as a cumulative effect of a change in accounting principle as described in note 2.

Other operating (income) expense consists of the following:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Gain from sale of subsidiary (Data Management) (Note 23)	$ —	$ —	$ —	$(137,002)
Termination of employees and reorganization	582	19,235	9,570	11,443
Cost of 2001 re-audit and completion of 2002 audit	470	2,089	—	—
Canceled merger gain, net (Veritas) (Note 23)	—	—	(2,864)	—
Other	—	—	1,781	—
Total	$1,052	$21,324	$ 8,487	$(125,559)

NOTE 6 — Accounts Receivable, Net

Accounts receivable, net, consist of the following:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Accounts receivable — trade	$130,821	$173,744
Allowance for doubtful accounts	(3,115)	(4,608)
Total	$127,706	$169,136

Development of allowance for doubtful accounts is as follows:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 2002	Years ended December 2001
				(Restated)
	(In thousands of dollars)			
Beginning balance	$ 2,913	$ 4,648	$ 2,321	$ 3,353
New and additional allowances	837	2,615	5,955	1,281
Write-offs and reversals	(179)	(4,350)	(3,616)	(2,313)
Disposal of subsidiary	(127)	—	(12)	—
Ending balance	$ 3,444	$ 2,913	$ 4,648	$ 2,321
Presented as:				
Accounts receivable, net	$ 3,115	$ 2,472	$ 4,608	$ 2,160
Unbilled and other receivables	329	314	—	—
Assets of discontinued operations	—	127	40	161
Total	$ 3,444	$ 2,913	$ 4,648	$ 2,321

NOTE 7 — Other Current Assets

Other current assets consist of the following:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Prepaid operating expenses	$19,186	$23,815
Spare parts, consumables and supplies	11,348	7,814
Prepaid taxes	11,017	3,274
Produced oil, not lifted	4,569	2,748
Deferred steaming, mobilization	—	7,713
Advances to agents	5,123	197
Other	11,367	7,097
Total	$62,610	$52,658

NOTE 8 — Property and Equipment, Net

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

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Seismic vessels and equipment	$ 384,294	$ 1,121,435
Production vessels and equipment	679,748	1,713,785
Fixtures, furniture and fittings	11,786	67,326
Buildings and other	3,890	15,681
	1,079,718	2,918,227
Accumulated depreciation	(19,535)	(1,215,879)
Total	$ 1,060,183	$ 1,702,348

The Company had $656.6 million and $923.0 million in property and equipment under UK leases at December 31, 2003 and 2002, respectively.

When calculating impairments, the carrying values of assets or cash generating units are compared to their recoverable amounts, defined as the higher of estimated selling price and value in use. See Note 2 for further description of the accounting policy for impairments of long-lived assets. As seismic vessels and equipment are not separate cash-generating units, such assets are presented combined. Vessels and equipment subject to capital leases that are part of a cash-generating unit are no longer presented separately from the year ended December 31, 2003.

The following table summarizes depreciation expense, excluding impairments (see note 5) and capitalized interest:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Depreciation expense, net of amounts capitalized into multi-client library	$18,206	$121,485	$154,204	$140,698
Depreciation expense capitalized into multi-client library	1,329	11,766	31,528	30,234
Interest capitalized into property and equipment	$ —	$ —	$ —	$ 2,871

Significant impairment charges were recorded in each of the ten months ended October 31, 2003 and the year ended December 31, 2002 related to property and equipment. See Note 5.

NOTE 9 — 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:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Completed surveys:		
Completed during 1997, and prior years	$ 16,897	$ 17,700
Completed during 1998	20,527	31,052
Completed during 1999	40,402	64,064
Completed during 2000	40,140	99,837
Completed during 2001	139,154	227,758
Completed during 2002	54,520	80,617
Completed during 2003	74,686	—
Completed surveys	386,326	521,028
Surveys in progress	21,679	62,831
Multi-client library	$408,005	$583,859

The following table summarizes impairment charges, amortization and capitalization of interest and depreciation related to the multi-client library:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	2001
		(In thousands of dollars)		(Restated)
Impairment charges (note 5)	$ —	$ 90,053	$200,393	$ 12,686
Amortization expense	33,347	148,399	195,954	182,123
Interest capitalized into multi-client library	375	2,083	4,841	12,645
Depreciation capitalized into multi-client library	$ 1,329	$ 11,766	$ 31,528	$ 30,234

The application of the Company's minimum amortization requirements to the components of the existing multi-client library is summarized as follows:

	Successor Company
	Minimum future amortizations
	(In thousands of dollars)
During 2004	$ 73,073
During 2005	96,393
During 2006	95,937
During 2007	77,925
During 2008	59,457
During 2009	5,220
Future minimum amortization	$408,005

These minimum amortization requirements are calculated as if there will be no future sales of these components. The Company believes that the likelihood of incurring these minimum amortization amounts is remote because amortization generated by multi-client sales in the ordinary course of business is expected to substantially reduce the book value of the multi-client library.

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 year even if the aggregate amount of ordinary amortization charges recognized exceeds the aggregate minimum amortization charges above.

NOTE 10 — Intangible Assets, Net

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

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Existing technology	$33,011	$ —
Existing contracts	17,600	—
Order backlog	5,401	—
Patents, royalties and licenses	85	20,230
Total cost	56,097	20,230
Accumulated amortization	(3,488)	(14,893)
Total	$52,609	$ 5,337

Intangible assets existing at December 31, 2003 were primarily recognized in conjunction with the adoption of fresh start reporting, effective November 1, 2003. Total amortization expense was $3.5 million for the two months ended December 31, 2003, $1.5 million for the ten months ended October 31, 2003 and $4.9 million and $8.3 million for the years ended December 31, 2002 and 2001, respectively. The weighted remaining amortization period for intangible assets as of December 31, 2004 is 6.2 years, and the amortization expense related to these assets, under existing amortization plans, for the next five years is $13.6 million (2004), $11.8 million (2005), $6.7 million (2006), $4.2 million (2007) and $3.8 million (2008).

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 in a subsequent period, the tax effect will be recorded as a reduction of the carrying value of intangible assets. Such reduction will reduce future amortization expense related to these assets.

As described in note 2, as of January 1, 2002, the Company recognized $163.6 million in non-cash impairment charges of goodwill as a result of the transition provisions of SFAS 142. In addition, in 2002, the Company recorded a goodwill impairment charge of $9.4 million related to its Marine Geophysical reporting unit due to identified impairment factors, which included a significant reduction in the market value of the Company.

In accordance with the provisions of SFAS 142, the Company did not recognize any goodwill amortization during the year ended December 31, 2002 and periods ended October 31 and December 31, 2003. Goodwill amortization for the year ended December 31, 2001 was $5.2 million (excluding goodwill amortization on operations presented as discontinued operations).

NOTE 11 — Other Long-Lived Assets

Other long-lived assets consist of the following:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Governmental grants and contractual receivables	$16,772	$17,238
Prepaid pension cost and long term receivables	6,947	9,400
Favorable lease contracts	13,806	—
Deferred debt issue costs	—	14,942
Total	$37,525	$41,580

Governmental grants and contractual receivables relate to grants from the Norwegian Government and contractual payments from FPSO contract counterparts that the Company is entitled to receive to cover parts of its asset removal obligations (note 2 and 13).

The fair value of certain favorable lease contracts were recognized in the Company's balance sheet in connection with the adoption of fresh start reporting, effective November 1, 2003. The amortization of this asset over the remaining lease period (which averages approximately 6 years) is recorded as an increase of lease expense as part of cost of sales.

NOTE 12 — Accrued Expenses

Accrued expenses consist of the following:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Accrued employee benefits	$ 30,199	$ 38,208
Accrued debt restructuring costs	25,218	1,166
Accrued vessel operating costs	25,126	34,315
Customer advances and deferred revenue	12,614	35,236
Accrued severance costs	5,061	1,215
Accrued interest costs	2,658	45,448
Other	46,460	63,956
Total	$147,336	$219,544

Accrued debt restructuring costs as of December 31, 2003 includes $22.7 million of excess cash (as defined in the Chapter 11 restructuring agreement) payable to creditors of the Company under the restructuring agreement. The amount was paid in May 2004.

Changes in accrued severance and restructuring are as follows:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001
	(In thousands of dollars)			(Restated)
Beginning balance	$ 8,367	$ 1,215	$ —	$ —
Additional allowances	1,764	18,469	1,215	—
Severance and restructuring costs paid	(5,070)	(11,317)	—	—
Ending balance	$ 5,061	$ 8,367	$1,215	$ —

NOTE 13 — Other Long-Term Liabilities

Other long-term liabilities consist of the following:

	Successor Company	Predecessor Company
	December 31, 2003	December 31, 2002
	(In thousands of dollars)	
Deferred gain and accrued liabilities UK leases (Note 19)	$ 78,120	$ 26,636
Pension liability (Note 21)	45,185	12,623
Asset Retirement Obligations (Note 2)	50,016	58,215
Other	24,342	26,722
Total	$197,663	$124,196

NOTE 14 — Short-Term Debt and Current Portion of Long-Term Debt

Short-term debt and current portion of long-term debt consist of the following:

	Successor Company	Predecessor Company
	December 31, 2003	December 31, 2002
	(In thousands of dollars)	
Revolving bank credit facility(a)	$ —	$ 430,000
Bank credit facility	—	48
Bank credit facility(a)	—	250,000
Bank loan related to multi-client securitization program	—	63,955
Current portion of long-term debt (see Note 15)	18,512	261,058
Total	$18,512	$1,005,061

(a) Debt compromised in the Chapter 11 proceeding.

The revolving bank credit facility ($430 million) and the bank credit facility ($250 million) had average interest rates as of December 31, 2002 of 1.94% and 5.92%, respectively.

NOTE 15 — Long-Term Debt

Long-term debt consists of the following:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Unsecured:		
10% Senior Notes, due 2010	$ 745,950	$ —
8% Senior Notes, due 2006	250,000	—
Debt compromised in the Chapter 11 proceeding	—	1,455,729
LIBOR + 1.15% Unsecured senior term loan, due 2011	4,811	—
Secured:		
8.28% First Preferred Mortgage Notes, due 2011	109,119	118,480
Other loan, due 2006	17,306	7,188
Total debt	1,127,186	1,581,397
Less current portion	(18,512)	(261,058)
Total long-term debt	$1,108,674	$1,320,339

Aggregate maturities of long-term debt as of December 31, 2003 are as follows:

	Successor Company (In thousands of dollars)
2004	$ 18,512
2005	19,381
2006	263,586
2007	13,255
2008	14,394
Thereafter	798,058
Total	$1,127,186

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 then. The 10% Notes are not callable until November 2007 and are callable thereafter at par plus a premium of 5% declining linearly until maturity. The 8% Senior Notes, due 2006 ("8% Notes") bear interest at 8% payable semi-annually and mature in November 2006 with no required principal payments until then. The 8% Notes are callable from November 2003 at par plus a premium of 3% declining linearly until maturity. Both the 10% Notes and 8% Notes are unsecured obligations of PGS ASA and are guaranteed by certain material subsidiaries.

The 8.28% First Preferred Mortgage Notes, due 2011 ("8.28% Notes") bear interest at 8.28% payable semi-annually to the bondholders along with scheduled principal payments. The Company is required to make monthly sinking fund payments to the indenture trustee in the amount of $50,000 per day. These monthly payments are designed to meet semi-annual interest and principal payments and are held in trust by the indenture trustee until the semi-annual payments are made. The 8.28% Notes are secured by, among other things, two seismic vessels. In addition the indenture trustee has an irrevocable deposit of $10 million as security for future interest and principal payments; this deposit is presented as long-term restricted cash in the consolidated balance sheet because the monies will be used to make final debt service payment when the 8.28% Notes are retired. The 8.28% Notes are not callable until June 2006 and are callable thereafter at par plus a make whole premium based on US treasury rates plus 0.375%.

In May 2004, the Company repaid its loan of $4.8 million, which had an original maturity date in 2011.

Covenants.

In addition to customary representations and warranties, the Company's loan and lease agreements include various covenants. Certain of the Company's debt agreements contain covenants restricting it from incurring debt unless certain coverage ratios are met and limiting financial indebtedness, excluding project company debt, to $1.5 billion. These debt agreements also restrict, among other things: payment of dividends; ability to place liens on assets; the amount of subsidiary financial indebtedness; certain sale/leaseback transactions; certain transactions with affiliates; investments in project companies; investment in multi-client library; and asset dispositions.

Certain of the loan and lease agreements and the senior note indenture contain requirements to provide audited US GAAP financial statements by June 30 of each year and to provide unaudited US GAAP quarterly financial statements within a specified period (typically 60 days) after the end of each of the first three quarters. The Company received waivers and amendments allowing it to report under Norwegian GAAP in lieu of US GAAP until June 30, 2005.

The Company is in compliance with its loan covenants as of December 31, 2003 and currently.

Pledged Assets.

Seismic vessels and related equipment carrying a book value of $59.8 million and $106.0 million at December 31, 2003 and 2002, respectively, are pledged as security for certain indebtedness.

Letter of Credit and Guarantees.

The Company had aggregate outstanding letters of credit and related types of guarantees that are not reflected in the accompanying consolidated financial statements of $31.0 million and $9.5 million at December 31, 2003 and 2002, respectively.

Subsequent Event.

In March 2004, the Company entered into a secured $110.0 million credit facility with a bank, consisting of a $70.0 million revolving credit facility and a $40.0 million letter of credit facility. The Company may borrow US dollars under the revolving credit facility for working capital and general corporate purposes, and the letter of credit facility can be utilized in various currencies to obtain letters of credit to secure, among other things, performance and bid bonds required in the Company's ongoing business. The credit facility matures in March 2006 and is secured by certain assets. The interest rate for borrowings under the credit facility is LIBOR plus 2%. The credit facility is an obligation of PGS ASA and is guaranteed by certain material subsidiaries.

NOTE 16 — Interest Expense

Interest expense consists of the following:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Interest expense, gross	$(17,245)	$(92,504)	$(143,168)	$(152,205)
Interest on trust preferred securities	—	(8,536)	(14,974)	(14,935)
Interest capitalized	375	2,083	4,841	15,516
Total interest expense	$(16,870)	$(98,957)	$(153,301)	$(151,624)

NOTE 17 — Other Financial Items, Net

Other financial items, net, consists of the following:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Interest income	$ 1,050	$ 4,467	$ 4,214	$ 5,577
Foreign currency loss	(5,208)	(4,286)	(10,915)	(1,717)
Gain (loss) on TES	—	—	45,264	(9,111)
Other	(106)	(1,653)	(4,771)	(1,018)
Financial expense, net	$(4,264)	$(1,472)	$ 33,792	$(6,269)

During 1998 and 1999, the Company entered into forward foreign currency exchange contracts known as tax equalization swaps ("TES") related to its senior unsecured notes, its 8.28% First Preferred Mortgage Notes and its trust preferred securities. In 2002, all outstanding TES contracts were terminated. The changes in fair value of the TES for the years ending December 31, 2002 and 2001, are included in other financial items, net with $45.3 million and ($9.1) million, respectively. Reference is made to discussion in note 2 — Derivative Financial Instruments.

NOTE 18 — Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, other current assets, accounts payable and accrued expenses and other current liabilities approximate their respective fair values because of the short maturities of those instruments. The carrying amounts and the estimated fair values of other financial instruments are summarized as follows:

	Successor Company December 31, 2003		Predecessor Company December 31, 2002	
	Carrying amounts	Fair values	Carrying amounts	Fair values
	(In thousands of dollars)			
Debt	$1,127,186	$1,185,313	$2,325,400	$1,103,354
Trust preferred securities	—	—	142,322	7,648

The carrying amounts of the revolving bank credit facility approximate their fair values. The fair values of the other long-term debt instruments and trust preferred securities are estimated using quotes obtained from dealers in such financial instruments.

NOTE 19 — Commitments and Contingencies

Leases.

The Company has operating lease commitments expiring at various dates through 2013. The Company also has capital lease commitments expiring at various dates through 2008. Future minimum payments related to non-cancelable operating and capital leases, with lease terms in excess of one year, existing at December 31, 2003 are as follows:

	December 31, 2003	
	Operating leases	Capital leases
	(In thousands of dollars)	
2004	$ 50,398	$ 22,688
2005	26,962	30,935
2006	18,059	21,623
2007	16,800	6,882
2008	16,879	7,156
Thereafter	29,742	—
Total	$158,840	89,284
Imputed interest		(5,848)
Net present value of capital lease obligations		83,436
Current portion of capital lease obligations		(19,963)
Long-term portion of capital lease obligations		$ 63,473

Future minimum payments related to non-cancelable operating leases reflect $11.0 million and $7.6 million in sublease income for 2004 and 2005, respectively, 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, 2003
	(In thousands of dollars)
Marine seismic and support vessels	$ 15,381
FPSO shuttle tankers	77,388
Operations computer equipment	5,760
Buildings	60,239
Fixtures, furniture and fittings	72
Total	$158,840

Rental expense for operating leases, including leases with terms of less than one year, was $12.2 million for the two months ended December 31, 2003, $76.3 million for the ten months ended October 31, 2003, and $105.4 million and $117.9 million for the years ended December 31, 2002 and 2001, respectively. Rental expense for operating leases, net of sub-lease income related to a time charter of two FPSO shuttle tankers to a third party, is as follows: $1.4 million for the two months ended December 31, 2003, $16.6 million for the ten months ended October 31, 2003, and $21.7 million and $13.8 million for the years ended December 31, 2002 and 2001, respectively.

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 of the *Ramform Banff* for terms ranging from 20-25 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 ("Tax Indemnities") 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 asset. The UK Inland Revenue ("Inland Revenue") has not signed off on the Lessors' claims to capital allowances with respect to the Company's UK leases. The Company understands that the Inland Revenue has generally deferred agreeing to the capital allowances claimed under such leases pending the outcome of a case that has been appealed to the UK House of Lords (the highest UK court of appeal). It is generally believed that a ruling will be rendered late 2004. In that case, the Inland Revenue is challenging capital allowances associated with a defeased lease.

For various reasons, including the fact that the Company's leases differ qualitatively from the lease structure in the pending legal proceeding, the Company believes it is unlikely that its leases will be successfully challenged by the Inland Revenue. However, the Company cannot predict what, if any, liability it may incur relating to the Tax Indemnities because it is not possible to know what, if any, events will happen in the future that might result in tax consequences for which the Lessors are indemnified.

In addition, the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available under the UK lease related to the *Petrojarl Foinaven.* 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 rentals would correspondingly increase (and then decrease).

For fresh start reporting purposes, the Company has estimated and recorded the fair value of the specific tax exposure related to defeased UK leases noted above using a probability-weighted analysis and a range of possible outcomes. The Company has, therefore, recorded a 16.7 million British Pounds Sterling (approximately $28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. At December 31, 2003 this liability amounted to 16.7 million British Pounds Sterling or $29.5 million.

The Defeased Rental Payments are based on assumed Sterling LIBOR rates between 8% and 9% (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 pays rentals in excess of the Defeased Rental Payments (the "Additional Required 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. 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% discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British Pounds Sterling (approximately $51.6 million) at November 1, 2003, and 27.4 million British Pounds Sterling (approximately $48.6 million) at December 31, 2003.

NOTE 20 — Income Taxes

The expense (benefit) for income taxes from continuing operations consists of the following:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Current taxes:				
Norwegian	$ 394	$ 6,639	$ —	$ 4,314
Foreign	1,558	15,373	23,801	2,579
Deferred taxes:				
Norwegian	(1,575)	2,025	158,846	(77,048)
Foreign	(4,226)	(3,943)	3,243	98,499
Total	$(3,849)	$20,094	$185,890	$ 28,344
Classification in Consolidated Statements of Operations:				
Income tax expense (benefit)	(3,849)	21,911	185,890	28,344
Fresh start adoption	—	(1,817)	—	—
Total income tax expense (benefit)	$(3,849)	$20,094	$185,890	$ 28,344

The net expense (benefit) for the two months ended December 31, 2003, the ten months ended October 31, 2003 and the years ended 2002 and 2001 include $3.1 million, $182.8 million, $61.0 million and $92.5 million, respectively, in valuation allowance charges related to deferred tax assets (see table below).

The net expense (benefit) for the ten months ended October 31, 2003 and the years ended December 31, 2002 and 2001 include $2.0 million, $15.0 million and $(16.2) million, respectively, related to the resolution of uncertainties regarding outstanding tax issues.

The net expense (benefit) for the years ended December 31, 2002 and 2001 exclude $9.6 million and $4.2 million, respectively, related to discontinued operations.

The Company evaluated the need for valuation allowances related to its deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. The Company has recorded valuation allowances for 100% of net deferred tax assets due to cumulative losses in recent years and management's expectations about the generation of taxable income from contracts that are currently in effect. Because of these cumulative losses and future expectations, the Company has concluded that it was more likely than not that the net deferred tax assets would not be realized and have recognized the valuation allowances accordingly. The Company believes that it has valid tax planning strategies that may ultimately be successful in utilizing those net deferred tax assets. To the extent that the Company continues to generate deferred tax assets, it will continue to assess the need for valuation allowances related to those assets. Short term deferred tax asset that is recognized in the Consolidated Balance Sheets without valuation allowance is offset by long term deferred tax liabilities within the same tax jurisdiction.

Changes in valuation allowance are as follows:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	2001 (Restated)
	(In thousands of dollars)			
Balance at the beginning of the period	$365,439	$182,581	$121,498	$ 28,907
Additions	3,111	182,858	61,083	92,591
Balance at the end of the period	$368,550	$365,439	$182,581	$121,498

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		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	2001 (Restated)
	(In thousands of dollars)			
Income (loss) from continuing operations before income taxes, minority interest, discontinued operations, and cumulative effect of change in accounting principles:				
Norwegian	$(16,755)	$ 623,654	$(547,030)	$ (70,985)
Foreign	3,198	(46,052)	(76,205)	(40,800)
Total	(13,557)	577,602	(623,235)	(111,785)
Norwegian statutory rate	28%	28%	28%	28%
Expense (benefit) for income taxes at statutory rate	(3,796)	(161,729)	(174,506)	(31,300)
Increase (reduction) in income taxes from:				
Foreign earnings taxed at other than statutory rate	(440)	(2,057)	(8,023)	(14)
Petroleum surtax(a)	(1,619)	5,908	(2,503)	—
Non taxable gain on debt discharge	—	(351,078)	—	—
Non-recurring taxes related to Norwegian shipping regime	—	—	—	(24,631)
Exit Norwegian shipping regime 2002	—	—	78,859	—
Prior year adjustment in regards to exit Norwegian shipping regime 2001	—	—	82,141	—
Goodwill impairment	—	—	48,462	—
Taxable gain (loss) from local currency other than reporting currency	(1,495)	372	91,020	(1,524)
Other permanent items	390	22,362	9,357	(6,778)
Deferred tax asset valuation allowance	3,111	182,858	61,083	92,591
Total income tax expense (benefit)	$ (3,849)	$ 20,094	$ 185,890	$ 28,344

(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:

	Successor Company		Predecessor Company	
	December 31, 2003		December 31, 2002	
	(In thousands of dollars)			
	Asset	Liability	Asset	Liability
Current assets	$ (11,803)	$ 2,188	$ (15,372)	$ 920
Property, equipment and other long-lived assets	(55,035)	120,585	(62,216)	247,427
Tax losses carried forward	(326,622)	—	(227,786)	281
Deferred gain (loss)	(63,419)	37,583	(69,263)	45,470
Tax credits	(3,855)	—	(3,665)	—
Expenses deductible when paid	(31,208)	—	(52,247)	—
Other temporary differences	(37,833)	13,773	(27,009)	4,091
Total deferred tax (asset) liability before valuation allowance	(529,775)	174,129	(457,558)	298,189
Deferred tax asset valuation allowance	368,550		182,581	
Deferred tax (asset) liability	$(161,225)	$174,129	$(274,977)	$298,189
Net deferred tax liability — Norwegian		10,980		10,520
Net deferred tax liability — Foreign		1,924		12,692
Net deferred tax liability		$ 12,904		$ 23,212
Classification in Consolidated Balance Sheets:				
Short-term deferred tax asset		$ —		$ (1,193)
Short-term deferred tax liability		2,166		—
Long-term deferred tax liability		10,738		24,405
Net deferred tax liability		$ 12,904		$ 23,212

Norwegian tax loss carried forward of $618.1 million expire at various dates from 2009 through 2013. Tax loss carried forward in the UK, Brazil, Singapore and Australia totaling $510.5 million carry forward indefinitely. US tax loss carried forward of $19.8 million expire between 2019 and 2023. It is the Company's current policy not to 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 indefinitely. As of December 31, 2003 and 2002, the Company did not have any such unremitted earnings.

A foreign subsidiary was until 2002 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. The subsequent decision 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 depreciations. 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 21 — Post-Retirement Benefits

The Company sponsors defined benefit pension plans for substantially all of its Norwegian and UK employees, with eligibility determined by certain period-of-service requirements. These plans are generally funded through contributions to insurance companies. It is the Company's general practice to fund amounts to these defined benefit plans, which are sufficient to meet the applicable statutory requirements. At December 31, 2003, 1,122 employees were participating in these plans.

Reconciliation of the plans' aggregate projected benefit obligations and fair values of assets are summarized as follows:

Change in projected benefit obligations:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Projected benefit obligations at beginning of period(a)	$ 90,478	$46,111
Service cost	1,204	7,928
Interest cost	1,207	3,108
Employee contributions	—	1,503
Payroll tax	1,359	1,198
Actuarial (gain) loss, net	3,338	64
Benefits paid	—	(2,022)
Exchange rate effects	4,269	15,443
Projected benefit obligations at end of year	$101,855	$73,333

(a) Projected benefit obligations at beginning of period in the column for 2003 refers to fresh start reporting as of November 1, 2003.

Change in plan assets:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Fair value of plan assets at beginning of period(b)	$50,134	$ 34,571
Return on plan assets	819	3,439
Employer contributions	504	10,202
Employee contributions	—	1,503
Amendments	—	(10,262)
Benefits paid	—	(2,022)
Exchange rate effects	1,875	10,713
Fair value of plan assets at end of year	$53,332	$ 48,144

(b) Fair value of plan assets at beginning of period in the column for 2003 refers to fresh start reporting as of November 1, 2003.

The aggregate funded status of the plans and amounts recognized in the Company's balance sheets are summarized as follows:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Funded status	$(48,523)	$(24,358)
Unrecognized actuarial loss	3,338	13,404
Unrecognized prior service cost	—	25
Unrecognized transition obligation	—	154
Net amount recognized as accrued pension liability	$(45,185)	$(10,775)

Net amount recognized as accrued pension liability is presented as follows:

	Successor Company	Predecessor Company
	December 31,	
	2003	2002
	(In thousands of dollars)	
Other long-term assets	$ —	$ 1,848
Other long-term liabilities	(45,185)	(12,623)
Net amount recognized as accrued pension liability	$(45,185)	$(10,775)

The accumulated benefit obligation for all defined benefit pension plans was $81.4 million and $55.9 million as of December 31, 2003 and 2002, respectively.

Assumptions used to determine benefit obligations:

	December 31, 2003			December 31, 2002		
	Plan I	Plan II	Plan III	Plan I	Plan II	Plan III
Discount rate	6.0%	6.0%	5.3%	6.5%	7.0%	5.5%
Return on plan assets	7.0%	7.0%	7.5%	7.5%	8.0%	7.5%
Benefit increase	3.0%	3.0%	4.7%	4.0%	3.3%	4.2%
Annual adjustment to pensions	3.0%	3.0%	3.0%	3.3%	3.3%	2.5%

The measurement dates used to calculate the actuary measurements are approximately one month prior to balance sheet dates.

The aggregate net periodic pension costs for the Company's defined benefit pension plans is summarized as follows.

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	2001
	(In thousands of dollars)			
Service cost	$1,204	$ 7,145	$ 7,928	$ 7,641
Interest cost	1,207	3,247	3,108	2,693
Expected return on plan assets	(819)	(2,977)	(3,439)	(2,591)
Amortization of actuarial loss (gain)	(80)	403	1,908	26
Amortization of prior service cost	—	3	2	3
Amortization of transition obligation	—	17	15	14
Payroll tax	266	397	367	347
Net periodic pension cost	$1,778	$ 8,235	$ 9,889	$ 8,133

Information for pension plans with an accumulated benefit obligation in excess of plan assets are as follows:

	Successor Company December 31, 2003	Predecessor Company December 31, 2002
	(In thousands of dollars)	
Projected benefit obligation	$89,819	$54,130
Accumulated benefit obligation	72,151	40,744
Fair value of plan assets	45,074	29,001

The Company's pension plan asset allocation at December 31, 2003 and 2002, by asset category, are presented by major plan group as follows:

	Successor Company December 31, 2003			Predecessor Company December 31, 2002		
	Plan I	Plan II	Plan III	Plan I	Plan II	Plan III
	(In thousands of dollars)					
Fair value of plan assets	$15,280	$14,907	$23,145	$12,688	$12,508	$22,948
Bonds	62%	57%	—	54%	59%	—
Equity securities	13%	14%	74%	11%	7%	97%
Other	25%	29%	26%	35%	34%	3%
Total	100%	100%	100%	100%	100%	100%

Substantially all employees not eligible for coverage under the defined benefit plans described above are eligible to participate in other retirement plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans. Under the Company's US defined contribution 401(k) plan, essentially all US employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 15% of compensation, subject to IRS and plan limitations, on a pre-tax basis. Employee pre-tax contributions are matched by the Company up to 6% of compensation, with a 2003 statutory employee contribution cap of $12,000. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $0.2 million for the two months ended December 31, 2003, $1.2 million for the ten months ended October 31, 2003 and $1.2 million for each of the years ended December 31, 2002 and 2001. Contributions to the plan by employees for these periods were $0.6 million, $2.7 million, $3.8 million and $3.7 million, respectively. Aggregate employer and employee contributions under the Company's other plans for the two months ended December 31, 2003, the ten months ended October 31, 2003 and the years ended December 31, 2002 and 2001 totaled $0.1 million and $0.1 million (two months 2003), $2.1 million and $0.3 million (ten months 2003), $7.4 million and $3.0 million (2002) and $4.9 million and $2.7 million (2001).

NOTE 22 — 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). Accordingly, all agreements on share options for the Company's key employees and directors were also cancelled. No new 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 equalled 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 forward exercisable over a three-year period.

A summary of the status of the Company's share-based compensation plans as of December 31, 2003, 2002 and 2001, and changes during the years ended, is summarized as follows:

	Predecessor Company					
	December 31,					
	2003		2002		2001	
	Options	Weighted average exercise price	Options	Weighted average exercise price	Options	Weighted average exercise price
	(In thousands of options, except exercise prices)					
Outstanding at beginning of year	4,973.5	NOK135	8,635.4	NOK142	10,690.8	NOK135
Granted	—	—	—	—	120.0	NOK103
Exercised	—	—	—	—	(98.0)	NOK 75
Forfeited/cancelled	(4,973.5)	NOK135	(3,661.9)	NOK151	(2,077.4)	NOK108
Outstanding at December 31	—	—	4,973.5	NOK135	8,635.4	NOK142
Weighted average grant fair value of options granted during year		—		—		NOK 44

Exercisable options at December 31, 2002 and 2001 were 1,264,474 options at a weighted average exercise price of NOK 117 and 4,611,404 options at a weighted average exercise price of NOK 143, respectively.

NOTE 23 — Acquisitions and Dispositions

During 2001, the Company entered into a definitive business combination agreement with Veritas DGC, Inc., but in 2002, the agreement was terminated. The Company recognized a net gain of $2.9 million upon termination of the agreement representing the excess of a termination payment received from Veritas over the expenses incurred in connection with the proposed transaction. This amount was recognized in 2002 in the consolidated statements of operations as other operating (income) expense, net (see Note 5).

In March 2001, the Company sold its global Petrobank data management business and related software to Landmark Graphics Corporation, a subsidiary of Halliburton Company, for $165.7 million in net cash proceeds. The Company recognized a $137.0 million gain on the sale, net of taxes of $40.4 million.

On December 11, 2002, the Company sold its Production Services (formerly Atlantic Power Group) subsidiary to Petrofac Limited and recognized $26.8 million gross loss on disposal of this subsidiary in 2002, which included $35.4 million in goodwill impairments. The Company received proceeds of $20.2 million at the closing date and received an additional $3.8 million and $1.5 million in 2003 upon settlement of the working capital and certain contingent events, respectively. Furthermore, the Company recorded fair value of $2.0 million in connection with its adoption of fresh start reporting related to such contingent events as of November 1, 2003. The Company is eligible to receive an additional $6.0 million upon the occurrence of certain contingent events through 2010, which are not recognized since the realization of such amount is uncertain.

During February 2003, the Company sold its Atlantis oil and natural gas activities to Sinochem, and received proceeds of $48.6 million in addition to $10.6 million as reimbursements of outlays on behalf of Sinochem. The Company may receive up to $25.0 million in additional, contingent proceeds, which currently has not been recognized. During 2002, the Company recognized $174.1 million in impairment charges related to Atlantis, including the estimated loss on disposal.

On December 10, 2003, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. for deferred compensation of approximately $1.8 million, payable during 2004 and 2007, and may receive additional, contingent proceeds based on performance of that company through 2006. As of December 31, 2003, the Company had not received any such proceeds. The Company recognized no net gain or loss on the disposal of Tigress.

In connection with the adoption of fresh start reporting, the Company has recorded the fair value of all contingent proceeds from previous disposals.

The results of operations, net assets and cash flows for the above-mentioned subsidiaries have been presented as discontinued operations for 2003, 2002 and 2001, and are summarized as follows:

	Successor Company	Predecessor Company							
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31,						
			2002			2001			
	Tigress	Tigress	Tigress	Atlantis	Production services	Tigress	Atlantis (Restated)	Production services	
	(In thousands of dollars)								
Revenue	$ 137	$ 1,107	$ 1,684	$ 23,452	$ 181,302	$ 2,356	$ 575	$ 166,990
Operating expenses before depreciation, amortization, impairment and other operating income and expenses	(264)	(2,433)	(2,796)	(15,836)	(176,642)	(3,845)	(1,599)	(165,181)
Depreciation and amortization	—	(707)	(913)	—	(455)	(1,261)	(53)	(1,426)
Impairment of long-term assets	—	—	—	(169,284)	—	—	(20,817)	—
Other operating income and expenses	—	(512)	—	—	—	—	(633)	—
Total operating expenses	(264)	(3,652)	(3,709)	(185,120)	(177,097)	(5,106)	(23,102)	(166,607)
Operating profit (loss)	(127)	(2,545)	(2,025)	(161,668)	4,205	(2,750)	(22,527)	383
Financial expenses and other financial items, net	24	(1,237)	(1,278)	1,545	(74)	(1,144)	(2,310)	245
Income (loss) before income taxes and change in accounting principle	$(103)	$(3,782)	$(3,303)	$(160,123)	$ 4,131	$(3,894)	$(24,837)	$ 628
Capital expenditures of discontinued operations	$ —	$ 118	$ 135	$ 77,126	$ 103	$ 138	$ 54,103	$ 226

A reconciliation of income (loss) before income taxes and change in accounting principles, as reported above, and loss from discontinued operations, net of tax, as presented in the Consolidated Statements of Operations, is as follows:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Income (loss) from discontinued operations before income taxes and change in accounting principles	$(103)	$(3,782)	$(159,295)	$(28,103)
Loss on disposal	(32)		(31,580)	—
Additional proceeds	—	1,500	—	—
Income tax benefit (expense)	—	—	(9,588)	(4,251)
Goodwill impairments SFAS 142, net of tax	—	—	(674)	—
Loss from discontinued operations, net of tax	$(135)	$(2,282)	$(201,137)	$(32,354)

The Company recorded $0.7 million in goodwill impairment relating to its Tigress operations when implementing SFAS 142 as of January 1, 2002.

Allocation of interest expense to discontinued operations is based on actual interest charged to the respective entities.

As of December 31, 2003, the Company had no assets related to discontinued operations. As of December 31, 2002, the following assets and liabilities related to discontinued operations:

	Predecessor Company December 31, 2002 Tigress	Predecessor Company December 31, 2002 Atlantis
	(In thousands of dollars)	
Cash and cash equivalents	$ 427	$ 2,915
Accounts receivable, net	810	3,489
Other current assets	324	1,913
Property and equipment, net	214	323
Oil and natural gas assets, net	—	56,669
Other long-lived assets	1,684	—
Total assets	$ 3,459	$ 65,309
Short-term debt	$ —	$(15,800)
Accounts payable	(437)	(451)
Accrued expenses	(1,106)	(3,729)
Total liabilities	$(1,543)	$(19,980)

During August 2002, the Company purchased an aggregate 70% interest in PL 038 on the Norwegian Continental Shelf of the North Sea. The interest was purchased from Statoil (which held a 28% interest in PL038) and Norsk Hydro (which held a 42% interest in PL038). The Company's 30% partner is the Norwegian government's State Direct Financial Interest. As consideration for the 70% interest, the Company assumed a portion of the abandonment liabilities associated with PL 038, estimated and accrued at $35.4 million, as well as any future environmental liabilities that may be generated by exploration and production activities in the field. The Company's FPSO vessel, *Petrojarl Varg,* has been in production on the Varg field of the license since December 1998. The transaction was accounted for as an asset purchase.

NOTE 24 — Related Party Transactions

At December 31, 2003, 2002 and 2001, the Company owned 50% of the shares in Geo Explorer AS and had chartered a vessel from that company during these years. 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 share as Walther Herwig AS was de-merged) and chartered two vessels from that company in 2003, 2002 and 2001. Total lease expense recognized during the two months ended December 31, 2003, the ten months ended October 31, 2003 and the years ended December 31, 2002 and 2001 on these vessels was $1.1 million, $6.4 million, $8.9 million and $9.2 million, respectively. There are no remaining lease commitments related to these investees as of December 31, 2003.

As of December 31, 2003, the Chairman of the Board, Jens Ulltveit-Moe, through Umoe AS, controlled a total of 1,912,444 shares in PGS ASA. Jens Ulltveit-Moe became a major shareholder and took office as Chairman of the Board in 2002. Jens Ulltveit-Moe also has a 60% ownership interest in Knutsen OAS Shipping AS ("Knutsen"). Knutsen is chartering the MT Nordic Svenita and the MT Nordic Yukon vessels from PGS on a time charter contract and paid $20.1 million and $20.5 million to PGS under these contracts in 2003 and 2002, respectively. PGS charters the vessels from an independent third party. The vessels were chartered by PGS to shuttle the Banff field, but in 2001 were chartered to Knutsen on terms approximating PGS'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 $2.4 million and $1.8 million to Knutsen under this contract in 2003 and 2002, respectively. Mr. Ulltveit-Moe is also the Chairman of Unitor ASA, a company that from time to time provides the Company with equipment for its vessels. During the years ended December 31, 2003 and 2002, the Company hired a consultant from Umoe Invest AS, who became an employee of the Company in 2004.

NOTE 25 — Investments in associated companies

Income(loss) from associated companies accounted for using the equity method is as follows:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December 31, 2002	Years ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Corporations and limited partnerships:				
Geo Explorer AS	$119	$1,425	$ 142	$ 619
FW Oil Exploration LLC	—	—	(5,845)	(1,358)
Ikdam Production SA	81	162	(3,561)	223
Triumph Petroleum	—	(813)	(2,237)	(179)
General partnerships	—	—	—	5
Total	$200	$ 774	$(11,501)	$ (690)

Investments and advances to associated companies accounted for using the equity method are as follows:

	Book value December 31, 2002	Share of income 2003	Effect of fresh start adjustments 2003	Paid-in capital/ (dividends) 2003	Equity transactions 2003 (a)	Book value December 31, 2003	Ownership percent as of December 31, 2003
				(In thousands of dollars)			
Corporations and limited partnerships:							
Geo Explorer AS	$ 1,630	$1,544	$ —	$—	$ —	$3,174	50.0%
Triumph Petroleum(b)	2,793	(813)	—	—	(1,980)	—	0.0%
Ikdam Production, SA	4,712	243	(265)	—	—	4,690	40.0%
Walter Herwig AS(c)	1,107	—	—	—	(1,107)	—	100.0%
Others	132	—	—	—	—	132	
General partnerships	84	—	—	4	(14)	74	
Total	$10,458	$ 974	$(265)	$ 4	$(3,101)	$8,070	

(a) Includes foreign currency translation differences.

(b) The Company's interest in Triumph Petroleum was sold in July 2003.

(c) The Company increased the ownership percentage to 100% in Walter Herwig AS in December 2003. As of December 31, 2003, Walter Herwig AS is therefore consolidated in the financial statements.

NOTE 26 — Segment and Geographic Information

In 2003, the Company revised its organizational structure. Prior to 2003, PGS was organized and managed as two business segments, geophysical and production. Due to the increased size and importance of certain businesses within these segments and in order to improve its management structure, the Company now manages its overall business in four 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 the Company's onshore multi-client library;
- *Production,* which owns and operates four harsh environment FPSO vessels in the North Sea and owns a 40% equity investment in Ikdam production, SA; and
- *Pertra,* a small oil and natural gas company that owns 70% of and is the operator for PL 038 on the Norwegian Continental Shelf ("NCS") and also owns participating interests in two additional NCS licenses in areas that do not have current production.

All segment information presented below has been restated to reflect this revision in the organization structure. The Company manages its Marine Geophysical segment from Lysaker, Norway, its Onshore segment from Houston, Texas, and its Production segment and Pertra from Trondheim, Norway.

The principal markets for the Production segment are the UK and Norway. Pertra produces its oil in Norwegian waters, but oil is sold as a commodity worldwide. The Varg field (in PL 038), which is 70% owned and operated by Pertra, is produced using the FPSO *Petrojarl Varg*, which is owned and operated by the Company's Production segment. 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 Global Services/Corporate. Significant charges, which do not relate to the operations of any segment, such as debt restructuring costs, are also presented as Global Services/Corporate. Information related to operations held for sale/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 is not included in the measure of segment performance.

Information by business segment is summarized as follows:

	Marine geophysical	Onshore	Production	Pertra	Global services/ corporate	Elimination of affiliated sales	Total
	(In thousands of dollars)						
Revenue, unaffiliated companies:							
2003 (Successor — two months)	$ 99,283	$ 21,459	$ 39,745	$ 9,544	$ 2,340	$ —	$ 172,371
2003 (Predecessor — ten months)	498,719	128,965	210,437	112,097	11,646	—	961,864
2002 (Predecessor)	587,229	118,698	291,762	32,697	12,845	—	1,043,231
2001 (Predecessor) restated	486,097	98,535	290,394	—	18,204	—	893,230
Revenue, includes affiliates:							
2003 (Successor — two months)	$ 99,382	$ 21,459	$ 45,229	$ 9,544	$ 4,957	$ (8,200)	$ 172,371
2003 (Predecessor — ten months)	500,113	128,965	250,058	112,097	16,243	(45,612)	961,864
2002 (Predecessor)	587,640	118,698	306,645	32,697	16,022	(18,471)	1,043,231
2001 (Predecessor) restated	486,375	98,535	290,394	—	19,472	(1,546)	893,230
Depreciation and amortization:							
2003 (Successor — two months)	$ 37,342	$ 5,904	$ 10,441	$ 743	$ 1,269	$ —	$ 55,699
2003 (Predecessor — ten months)	191,215	29,425	43,418	30,826	6,692	—	301,576
2002 (Predecessor)	247,933	28,408	70,958	12,695	7,509	—	367,503
2001 (Predecessor) restated	233,837	13,879	80,759	—	8,005	—	336,480
Impairment of long-lived assets:							
2003 (Successor — two months)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Predecessor — ten months)	89,598	5,085	328	—	—	—	95,011
2002 (Predecessor)	220,594	5,906	331,971	—	—	—	558,471
2001 (Predecessor) restated	9,054	3,632	—	—	—	—	12,686
Other (income) expense, net:							
2003 (Successor — two months)	$ 1,189	$ 38	$ —	$ —	$ (175)	$ —	$ 1,052
2003 (Predecessor — ten months)	8,107	266	—	—	12,951	—	21,324
2002 (Predecessor)	1,341	2,625	—	—	4,521	—	8,487
2001 (Predecessor) restated	(135,112)	2,175	3,706	—	3,672	—	(125,559)
Operating profit (loss):							
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
2002 (Predecessor)	(188,532)	(21,791)	(246,601)	(9,204)	(22,481)	—	(488,609)
2001 (Predecessor) restated	96,495	(38,897)	18,344	—	(29,144)	—	46,798
Loss from discontinued operations, net of tax:(a)							
2003 (Successor — two months)	$ (135)	$ —	$ —	$ —	$ —	$ —	$ (135)
2003 (Predecessor — ten months)	(3,782)	—	1,500	—	—	—	(2,282)
2002 (Predecessor)	(3,977)	—	(22,660)	(174,500)	—	—	(201,137)
2001 (Predecessor) restated	(6,528)	—	(250)	(25,576)	—	—	(32,354)
Cumulative effect of change in accounting principles, net of tax							
2003 (Successor — two months)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Predecessor — ten months)	(779)	—	3,168	—	—	—	2,389
2002 (Predecessor)	—	—	(161,106)	—	(2,532)	—	(163,638)
Investment in associated companies:							
December 31, 2003 (Successor)	$ 3,308	$ —	$ 4,687	$ —	$ 75	$ —	$ 8,070
December 31, 2002 (Predecessor)	2,953	2,793	4,712	—	—	—	10,458

	Marine geophysical	Onshore	Production	Pertra	Global services/ corporate	Elimination of affiliated sales	Total
	(In thousands of dollars)						
Assets of discontinued operations:							
December 31, 2003 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2002 (Predecessor)	3,459	—	—	65,309	—	—	68,768
Assets, excluding discontinued operations:							
December 31, 2003 (Successor)	$ 959,261	$117,383	$ 790,316	$ 67,068	$ 63,332	$ —	$1,997,360
December 31, 2002 (Predecessor)	1,299,984	119,535	1,168,634	75,648	107,168	—	2,770,969
Additions to long-lived tangible assets:(b)							
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
2002 (Predecessor)	167,400	24,981	3,828	10,913	1,203	—	208,325
2001 (Predecessor) restated	184,790	12,665	122,753		1,356	—	321,564
Capital expenditures on discontinued operations:(a)							
2003 (Successor — two months)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Predecessor — ten months)	118	—	—	—	—	—	118
2002 (Predecessor)	135	—	103	77,126	—	—	77,364
2001 (Predecessor) restated	138	—	226	54,103	—	—	54,467

(a) Loss from discontinued operations, net of tax, and capital expenditures on discontinued operations, included in segment data for Pertra, relates to Atlantis, which was a part of the Company's oil and natural gas operations prior to its disposition in early 2003. The discontinued operations related to Tigress and Production services are related to Marine Geophysical and Production, respectively.

(b) Consists of cash investments in multi-client library and capital expenditures.

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, excluding assets held for sale) 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 located.

Information by geographic region is summarized as follows:

	Americas	UK	Norway	Asia/Pacific	Africa	Middle East/ Other	Elimination of affiliated sales	Total
	(In thousands of dollars)							
Revenue, unaffiliated companies:								
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
2002 (Predecessor)	235,010	275,706	227,104	154,821	80,393	70,197	—	1,043,231
2001 (Predecessor) restated	188,851	212,773	188,470	148,077	75,553	79,506	—	893,230
Revenue, includes affiliates:								
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
2002 (Predecessor)	235,610	278,611	230,022	154,851	80,393	70,197	(6,453)	1,043,231
2001 (Predecessor) restated	190,159	215,144	190,647	148,294	75,553	79,506	(6,073)	893,230
Total assets:								
December 31, 2003 (Successor)	$430,972	$870,941	$539,935	$111,484	$ 20,567	$23,461	$ —	$1,997,360
Capital expenditures (cash):								
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
2002 (Predecessor)	10,776	17,073	28,415	192	—	279	—	56,735
2001 (Predecessor) restated	5,290	69,919	71,637	208	312	170	—	147,536

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2003, 2002 and 2001.

For the years ended December 31, 2003, 2002 and 2001, customers exceeding 10% of the Company's total revenue were as follows (the table shows percentage of revenues accounted for by such customers, and the segments that had sales to the respective customers are marked with X):

	Years ended December 31,						
	2003			2002		2001	
Segments serving customer:	19%	12%	10%	15%	11%	14%	11%
Marine Geophysical	X	X	X	X	X	X	X
Onshore			X				
Production	X	X		X	X	X	X
Pertra	X				X		
Global Services/Corporate	X			X	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 27 — Supplemental Cash Flow Information

Cash paid during the year includes payments for:

	Successor Company	Predecessor Company		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Years ended December, 2002	2001 (Restated)
	(In thousands of dollars)			
Interest, net of capitalized interest	$19,619	$120,162	$112,543	$143,265
Interest on trust preferred securities	—	—	10,377	13,836
Income taxes	4,951	8,145	15,938	1,257

The Company entered into capital lease agreements for new equipment aggregating $0.6 million for the ten months ended October 31, 2003, $65.0 million and $41.8 million for the years ended December 31, 2002 and 2001, respectively. There were no new capital lease agreements during the two months ended December 31, 2003.

NOTE 28 — 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. The 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 US 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		
	Two months ended December 31, 2003	Ten months ended October 31, 2003	Year ended December 31, 2002	Year ended December 31, 2001 (Restated)
	(In thousands of dollars)			
Income Statement Data:				
Revenue	$ 17,610	$ 244,605	$ 286,261	$ 237,793
Operating loss	(26,009)	(4,238)	(52,245)	(113,762)
Net loss	(12,671)	(6,752)	(47,887)	(99,712)
Balance Sheet Data:				
Current assets	$ 99,453	$ 141,008	$ 146,061	$ 121,609
Noncurrent assets	148,951	123,182	157,137	168,054
Current liabilities	84,523	82,555	112,941	95,618
Noncurrent liabilities	408,479	416,699	385,920	320,473
Equity (deficit)	(244,598)	(235,064)	(195,663)	(126,428)

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 15), 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 US 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					
	Two months ended December 31, 2003		Ten months ended October 31, 2003		Years ended December 31,			
					2002		2001	
	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger
							(Restated)	
	(In thousands of dollars)							
Income Statement Data:								
Revenue	$ 1,183	$ 1,177	$ 6,032	$ 6,003	$ 7,458	$ 7,421	$ 7,681	$ 7,643
Operating profit	1,167	1,159	5,885	5,857	7,295	7,259	7,534	7,496
Net income	361	355	1,738	1,708	2,094	2,058	1,608	1,570
Balance Sheet Data:								
Current assets	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-current assets	69,295	69,031	72,964	72,719	71,879	71,651	74,099	73,906
Current liabilities	6,252	6,252	7,616	7,616	5,864	5,864	5,535	5,532
Non-current liabilities	49,658	49,657	52,324	52,336	54,729	54,729	59,373	59,373
Equity	13,385	13,122	13,024	12,767	11,286	11,058	9,191	9,001

NOTE 29 — Supplemental Information — Oil and Gas Reserves and Costs (Unaudited)

Pertra has 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 employs a Company FPSO to produce oil from PL 038. The revenues and expenses 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 using 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 the capitalization policies of each method. As a result, the Successor and Predecessor results of operations, capitalized costs and costs incurred information is not comparable.

Results of operations relating to oil and natural gas producing activities are as follows:

	Successor Company	Predecessor Company
	Two months ended December 31, 2003	Ten months ended October 31, 2003
	(In thousands of dollars)	
Oil revenues	$ 9,544	$112,097
Production costs	6,354	62,296
Other operating costs	604	2,136
Accretion of asset retirement obligation	271	1,821
Exploration costs	4,344	
Depletion, depreciation and amortization	739	30,815
Net income (loss) before tax	(2,767)	15,028
Income tax expense (benefit)	(2,159)	11,722
Net income (loss)	$ (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:

	Successor Company
	December 31, 2003
	(In thousands of dollars)
Capitalized Costs:	
Proved properties	$30,262
Unproved properties	4,000
Accumulated depreciation, depletion and amortization	(739)
Net	$33,523

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
	Two months ended December 31, 2003	Ten months ended October 31, 2003
	(In thousands of dollars)	
Exploration costs	$13,262	$16,253
Development costs	4,375	10,318
Total costs incurred	$17,637	$26,571

Proved Reserves and Standardized Measure

The estimates of proved oil and natural gas reserves for Pertra as of December 31, 2003 and 2002, were 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 December 31, 2003 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, 2003 and 2002 utilize respective oil prices of $29.97 and $28.86 per barrel (reflecting adjustments for oil quality). The Company's actual average sale price for oil produced in 2003 was $29.37 per barrel.

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 year ended December 31, 2003 and as of December 31, 2003. A company is required to disclose this information when it has significant oil and natural gas exploration and production activities. The Company meets the significant activities requirement for 2003, but did not meet the requirement for 2002 or 2001. As a result, only 2003 information is presented. In addition, it is not considered material to the disclosure to present the changes in reserves or the changes in Standardized Measure for the Predecessor and Successor periods during 2003.

The following tables provide a roll-forward of total proved reserves for the year ended December 31, 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, 2003 and the changes in Standardized Measure for the year ended December 31, 2003:

Estimated Quantities of Reserves (Unaudited)

Crude Oil	December 31, 2003 (In thousand barrels)
Proved Reserves:	
Beginning of the year	4,137
Extensions and discoveries	4,669
Purchases of producing properties	—
Revisions of previous estimates	3,067
Sales of producing properties	—
Production	(4,056)
End of year	7,818
Proved Developed Reserves:	
Beginning of year	3,272
End of year	2,114

Standardized Measure of Future Net Cash Flows from Proved Reserves (Unaudited)

	As of December 31, 2003
	(In thousands of dollars)
Future cash inflows	$234,300
Future production costs	109,010
Future development costs	12,900
Future abandonment costs	37,122
Future income taxes	59,906
Future net cash flows	15,362
Discount at 10% per annum	(369)
Standardized Measure	$ 15,731

Changes in Standardized Measure (Unaudited)

	Year ended December 31, 2003
	(In thousands of dollars)
Standardized Measure at beginning of year	$ 944
Revisions of reserves proved in prior years	49,280
Changes in prices and production costs	333
Changes in estimates of future development and abandonment costs	(10,760)
Net change in income taxes	(59,090)
Accretion of discount	94
Other, primarily timing of production	695
Extensions, discoveries and other additions, net of future production and development cost	75,102
Sales of oil and natural gas produced, net of production costs	(48,667)
Previously estimated development and abandonment costs incurred during the period	7,800
Net changes in Standardized Measure	14,787
Standardized Measure at end of year	$ 15,731

EXHIBIT 12.1

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: November 16, 2004

EXHIBIT 12.2

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: November 16, 2004