Petroleum Geo-Services ASA

Annual Report 2004

Important Events 2004

FINANCIAL AND STRATEGIC HIGHLIGHTS

- **Strategic choice made to develop PGS as an oil service group with focus on geophysics and floating production:**
  - Rejection of $900 million bid from CGG for PGS Geophysical
  - Finalizing divestment of Pertra in first quarter 2005
- **Completed a successful financial restructuring and regaining financial flexibility:**
  - Increased cash flow from operations
  - Net interest bearing debt reduced from $1,077 million at year end 2003 to $995 million at year end 2004
  - Financial flexibility further strengthened following divestment of Pertra
  - US GAAP historical reaudit accounts completed
  - NYSE re-listing in place December 17, 2004

OPERATIONAL HIGHLIGHTS

- Strong operations regularity and HSE statistics, recording the best safety performance ever by PGS
- Marine Geophysical experienced a difficult market in the first half of the year, followed in the second half of the year by a significantly improved balance between capacity and demand, improved marine seismic contract performance and strong multi-client late sales
- Onshore showed continued good operating performance but activity levels declined towards the end of the year due to completion of one out of two large projects in Mexico
- Production recorded high operating regularity overall, but production on *Petrojarl I* and *Petrojarl Varg* was negatively impacted by a labor conflict on the Norwegian Continental Shelf in the third and fourth quarter. In addition, production on the Varg field was reduced from the beginning of November due to damage of the main production riser
- Pertra was successfully developed through 2004. The total oil production was 5.3 million barrels in 2004 compared to 4.1 million barrels in 2003. Divested in first quarter 2005.

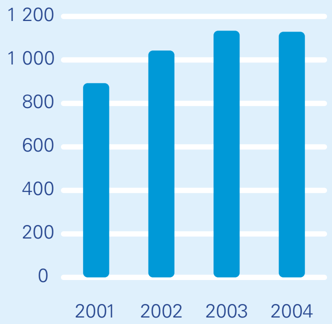
The information in this annual report is updated as of May 9, 2005. The Norwegian GAAP Financial Statements and Board of Directors' Report are dated March 31, 2005.

PGS has previously filed 2004 Annual Report of Form 20-F. The Report can be downloaded from our web site, www.pgs.com

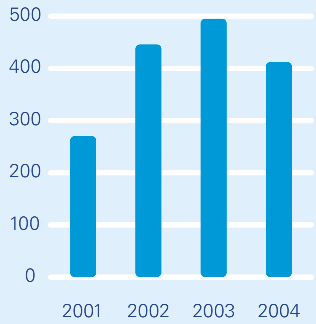
Contents

Key Figures
Petroleum Geo-Services

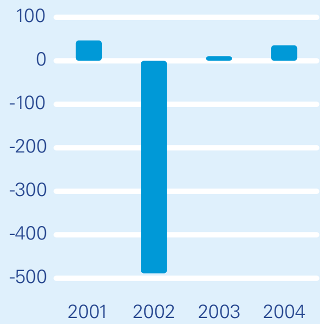
Revenues
In millions of dollars



Adjusted EBITDA
In millions of dollars



Operating profit (loss)
In millions of dollars



Financial Figures			
(US GAAP – In millions of dollars)	Year ended December 31, 2004	Year ended December 31, 2003*	Year ended December 31, 2002
Statement of operations data:			
Revenues	1 129.5	1 134.2	1 043.2
Adjusted EBITDA	412.2	495.2	445.9
Operating profit (loss)	35.7	20.5	(488.6)
Income (loss) from continuing operations before cumulative effect of change in accounting principles	(137.8)	547.1	(809.9)
Net income (loss)	(134.7)	547.0	(1 174.7)
Cash flow data:			
Cash flows provided by operating activities	282.4	227.1	294.6
Investment in multi-client library	41.1	90.6	151.6
Balance sheet data:			
Total assets	1 852.2	1 997.4	2 839.7
Multi-client library, net	244.7	408.0	583.9
Shareholders' equity (deficit)	222.9	353.6	(192.3)
Non-financial figures:			
Headcount (year end)	2 899	3 377	4 003
Lost Time Incident Frequency (LTIF)/million man hour	0.4	0.33	0.66

** Combination of successor and predecessor*

About PGS

PGS was formed as an oil service company and with the divestment of Pertra in March 2005, PGS will once again become fully focused on its oil service business with strategic focus on geophysics and floating production operations. We are industry leaders in both these areas, with strong credibility, market share, client relationships and technological expertise. The main goal for 2005 is to improve the return on these assets.

Business

Petroleum Geo-Services is a technologically focused oilfield service company involved in providing geophysical services worldwide and providing floating production services in the North Sea. Globally, we provide a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, we own and operate four harsh floating production, storage and offloading ("FPSO") units. In March 2005 we sold our small oil and natural gas company Pertra to Talisman.

Following the divestment of Pertra, our business is organized into three major business units: Marine Geophysical, Onshore and Production.

PGS headquarters are located at Lysaker, Norway. PGS has offices in 22 different countries with larger regional offices in London, Houston and Singapore, and currently employs over 2,900 full time staff. The revenues for 2004 were $1,129.5 million.

Our business priorities

Following our financial reorganization in 2003 and the sale of Pertra, we intend to create value for our shareholders by being a more focused oil-services group, building on increased cash flow from and returns on our present assets and pursuing selective growth opportunities.

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

Within Marine Geophysical, we intend to maintain our emphasis on high acquisition productivity and regularity in our operations and in customer delivery. We will seek to expand our market share in the data processing business and invest prudently in technology, equipment and multi-client seismic data.

Within Onshore, we will seek to expand our business by fully utilizing our present equipment, while selectively broadening our geographical market exposure.

Within our Production segment, we intend to maintain our position as a leader in harsh environment operations, while seeking growth opportunities in and outside the North Sea.

Market outlook

Over the past few years, oil and natural gas exploration and production companies have made relatively low investments in exploration. We believe that as companies continue to focus on replacing oil and natural gas reserves in the coming years, they will gradually become more active in exploration.

After a number of years of overcapacity in the marine seismic market, supply and demand are in more equilibrium, and consequently the market has improved and industry order backlog and margins have increased. We believe that PGS will continue to benefit from this trend.

Within floating production, we believe that increased industry focus on smaller fields and tail-end optimization forms a basis for growth in outsourcing where our Production segment is well positioned in the North Sea and has the potential to grow in selected international markets.

Core Values

Our Core Values are:

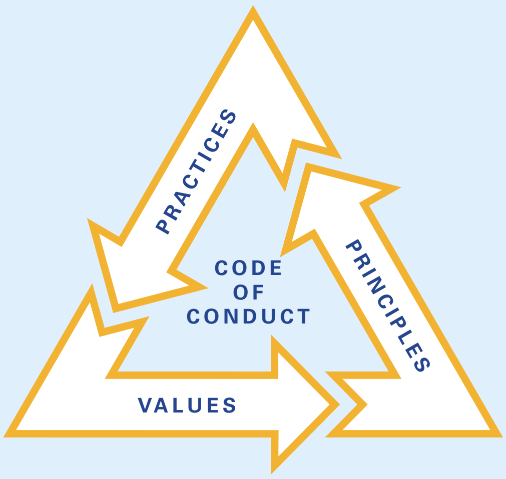
Leadership in HSE
We strive to establish and maintain best practice HSE culture throughout PGS. Our goal is zero injury to people and no damage to the environment. We work daily to achieve this.

People focus and integrity
We seek transparency in all our dealings and fully subscribe to a high standard of business ethics. We practice involvement, accountability and honesty. We respect and develop people – all of us are valued team members.

Initiative and innovation
We strive to put forward new ideas, break down boundaries and seek new solutions for PGS and our customers. We always encourage a proactive approach, even at the risk of some failures.

Delivery and reliability
We do our utmost to deliver what we promise to each other, to our clients, to our shareholders and society at large.

Code of Conduct



PGS has adopted a Code of Conduct that reflects our commitment to our shareholders, customers and employees to conduct our business with the utmost integrity.

Our Code of Conduct is an integration of our Values, Principles and Business Practices. Our Values are the foundation of how PGS conducts business. Principles of Conduct regulate how we maintain and implement our Values and we apply these principles to our Business Practices.

To maintain our ethical standards, we take responsibility for acting in compliance with laws and company policies. We act in a manner utilizing good judgement and encourage others to aspire to high ethical standards.

We encourage transparency and make ourselves available to address issues of concern.

For more details, see www.pgs.com.


– The revitalized PGS is a focused global oil services company.
Svein Rennemo,
President and CEO

Revitalized PGS

Last year we achieved what we set out to deliver in 2002: A Revitalized PGS. During 2004 PGS proved that it is capable of delivering excellent and improved services to its clients. As our markets continue to improve, I believe we are in a great position to further strengthen the already strong market position we have in our two businesses.

Our continued focus on HSE and the safety and well being of our employees does yield results. Safety performance and standards improved further in 2004 in all areas. HSE focus is and will remain an integral part of running our business.

Markets improved during the year, after a slow start in the first half of 2004 for Marine Geophysical. Higher oil prices are increasingly reflected in the spending patterns and in the project plans of our clients. This positively affected the market for oil-services in 2004, and points towards a stronger 2005 and 2006. In the markets for production services, the number of new projects is at a very high level and is rising. In Marine Geophysical, the second half of 2004 witnessed significant improvement in margins, multi-client late sales and order backlog, ending a prolonged period of soft market conditions for this industry. In the markets for onshore geophysical services, demand increased throughout 2004. We welcome the support from stronger markets. The PGS team continues to work hard to capture the full benefits of the upturn. We continue to give top priority to our efforts to improve operations and productivity to enhance cash flows and return on assets.

We improved the upside for some of our FPSO contracts last year by renegotiating key terms and prolonging the expected period of service. We continued the push to reduce steaming and increase the available production capacity of our marine geophysical vessels. We achieved further progress in capitalizing on our multi-client data library, through successfully expanding our Mega-Survey approach as an example. The emphasis on implementation efficiencies and project risk management continued to be rewarding for our onshore geophysical business.

With the divestment of our E&P company, Pertra, in early 2005, PGS is again a dedicated oil-services company. We now have a full commitment to the oil service business with strategic focus on geophysics and floating production operations. In these areas we are industry leaders with strong and proven credibility, market share, client relationships and technological expertise.

We re-listed on NYSE in December 2004, after filing audited US GAAP financial statements for 2003, 2002 and 2001 with the SEC in November. To the PGS Team this marked the successful completion of our financial restructuring efforts.

The revitalized PGS is a focused global oil services company. We have re-established a sound financial platform. We will utilize this platform to improve the return on our assets and to further build and strengthen PGS as a global oil services company.

Svein Rennemo
President and CEO

Marine Geophysical

PGS 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, to determine the size and structure of the reservoirs, and to help manage the production of reservoirs. PGS' Marine Geophysical business consists of streamer and seafloor seismic data acquisition, marine multi-client library and data processing.

Business

Seismic data is fundamental in the exploration, development and production of hydrocarbons. These data are used to assess prospectivity and identify potential hydrocarbon resources, to perform detailed mapping of the reservoirs in the field development phase, and to monitor how the reservoirs are being drained during the production phase.

Seismic acquisition

PGS has a total of ten 3D marine seismic streamer crews. The streamer fleet consists of:

- 6 Ramform vessels capable of towing up to 20 streamers
- 4 Classic streamer vessels capable of towing up to 6 streamers

The operational efficiency of the Ramforms allows PGS to be the only company that regularly offers 12 or more streamers as a standard acquisition configuration. Such technology and efficiency provides the perfect platform for Marine High Density 3D (HD3D℠).

PGS has one seafloor seismic crew that utilize a recording vessel, a source vessel and a cable laying vessel. Seafloor seismic or Ocean Bottom Cable acquisition are used in areas where conventional streamer acquisition operations are impossible or not economically feasible due to access limitations from shallow water or obstructions. Seafloor acquisition is also used when conventional streamer acquisition would not meet the desired geophysical objectives.

Market position

PGS is one of four major global participants in the marine 3D market, with a market share exceeding 30%. The PGS streamer acquisition fleet is the most modern in the industry.

2004 Operational performance

Marine Geophysical 2004 revenues decreased by $28.7 million as compared with 2003. Revenues from contract seismic acquisition decreased by $53.0 million, primarily due to a shut down of our ocean bottom 2C crew in late 2003.

Key figures Marine Geophysical (in millions of dollars, except head count)	2004 (US GAAP)	2003* (US GAAP)	2002 (US GAAP)
Revenues	570.8	599.5	592.6
Cost of sales, SG&A and R&D	364.1	325.4	311.3
Adjusted EBITDA	206.7	274.1	281.3
Depreciation and amortization	241.7	230.6	247.9
Other operating (income) expense, net	0.0	9.3	1.3
Impairment of long-lived assets	0.0	89.6	220.6
Operating profit	-35.0	-55.3	-188.5
Total assets	759.1	959.3	1 300.0
Head count	1 115	1 143	1 356

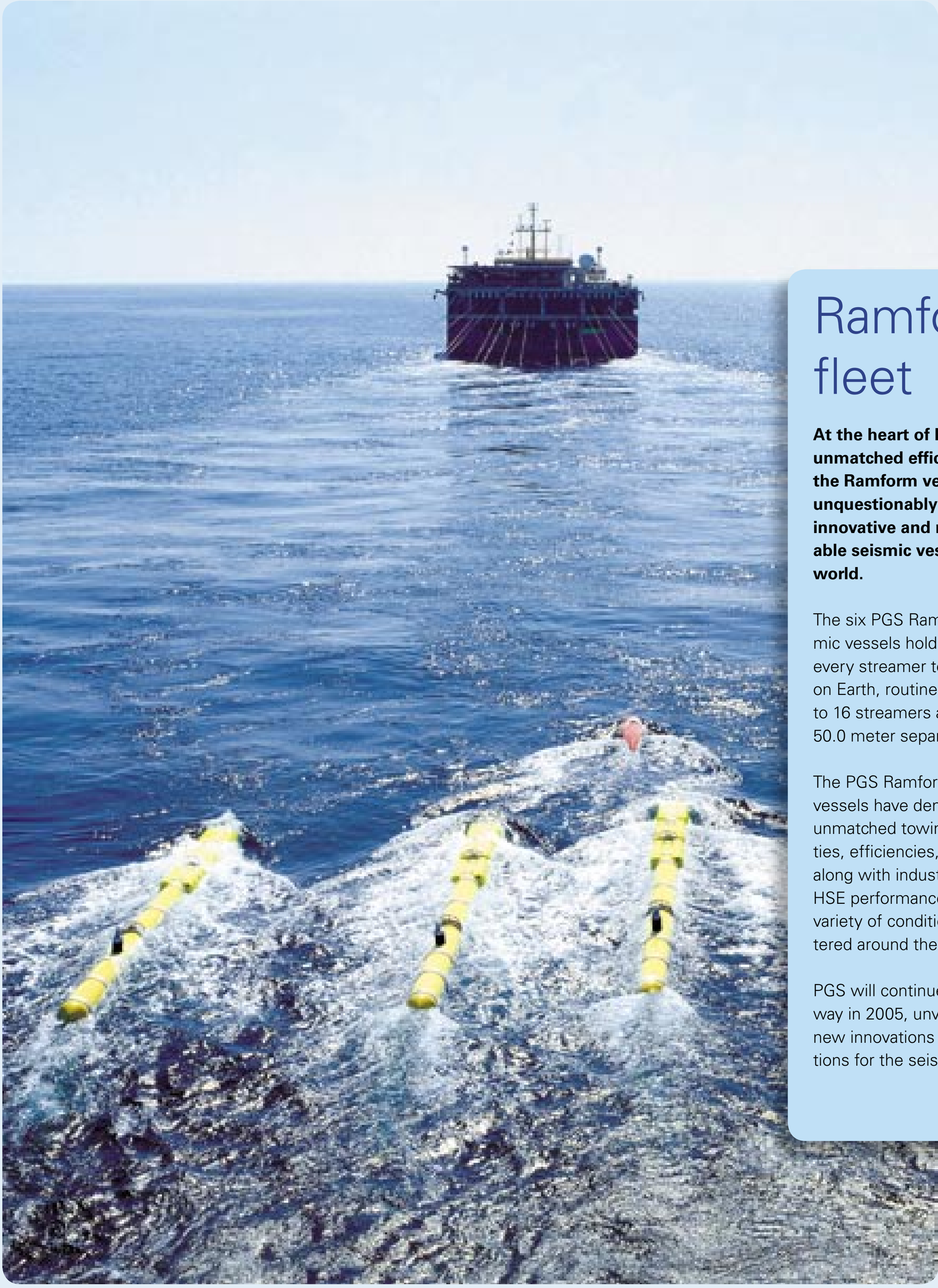
** Combination of successor and predecessor*

HD3D℠

The PGS High-Density 3D (HD3D℠) product is an outstanding example of project synergies between pre-survey planning, acquisition and processing.

The beginning of streamer HD3D℠ survey is a large, dense streamer towing configuration. The outcome of a HD3D℠ project is a premium seismic data product, having combined the optimum acquisition and processing technologies. HD3D℠ will deliver the highest resolution, highest quality 3D data product to address a broad range of problems and challenges, both related to exploration and time-lapse reservoir monitoring ("4D").

We intend to grow and consolidate our HD3D℠ strengths by developing new technologies that further improve efficiencies and that fully exploit the potential value of properly sampled seismic data.



Ramform fleet

At the heart of PGS' unmatched efficiency lies the Ramform vessel design, unquestionably the most innovative and recognizable seismic vessel in the world.

The six PGS Ramform seismic vessels hold virtually every streamer towing record on Earth, routinely towing 12 to 16 streamers at 37.5 to 50.0 meter separation.

The PGS Ramform seismic vessels have demonstrated unmatched towing capabilities, efficiencies, flexibility, along with industry leading HSE performance, in a wide variety of conditions encountered around the world.

PGS will continue to lead the way in 2005, unveiling many new innovations and directions for the seismic industry.

Pre-funding as a percentage of cash investments in multi-client data increased to 99% in 2004 compared to 72% in 2003. In 2004, we allocated the active vessel time for our seismic fleet between contract and multi-client data acquisition approximately 89% and 11%, respectively, as compared to approximately 81% and 19%, respectively, in 2003. Over time PGS expects to increase its multi-client investment from the very low 2004 levels.

After a weak first half of 2004, the balance between capacity and demand improved significantly in the second half resulting in improved prices and margins and an improved industry order backlog situation.

At December 31, 2004, our order backlog for contract seismic acquisition was $170 million for our Marine Geophysical segment compared with $105 million at December 31, 2003.

2004 HSE Performance

Marine Geophysical reported four Lost Time Incidents in 2004. The year ended with a Lost Time Incidents Frequency of 0.63 per million man hours and a Total Recordable Case Frequency of 1.42 per million man hours.

PGS recorded no environmental damage related to geophysical operations in 2004. In the beginning of January 2005 PGS Marine Geophysical "Environmental Management Manual" was released.

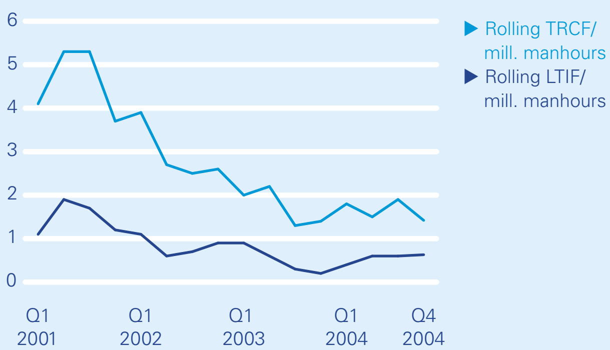
Outlook

In 2005 we expect seismic contract prices to increase driven by relatively high industry capacity utilization. We will continue our focus on contract acquisition, with a moderate increase in multi-client activity. We expect the multi-client late sales to be lower as compared with 2004 due to limited reinvestment over the past three years and expected delay of Brazilian 7th Licensing Round sales into 2006. We also expect increased costs due to increased fuel prices and a weaker U.S. dollar compared to 2004.

We expect that the capital expenditures in Marine Geophysical, excluding investments in multi-client library, in 2005 will be largely in line with 2004. Our capital expenditures in 2004 in Marine Geophysical were $56.9 million, while capitalized investment in multi-client library was $41.1 million.

We expect to spend approximately $25 million per year through 2008 to upgrade our marine seismic streamers.

PGS Marine Operations Safety Statistics Q1 2001 to present



Data Processing

Processing the seismic data with PGS' proprietary software allows for enhanced reservoir imaging and characterization, which improves:

- the 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
- the chances of maximizing total reserve recovery at the production stage.

Through the seismic data processing operations PGS provides:

- 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 PGS acquires
- multi-component and 4D seismic data processing for reservoir characterization and monitoring
- special process design to exploit the dense sampling of the HD3D℠ data acquisition
- specialized depth imaging of subsurface structures
- other specialized signal enhancement techniques

Backed by a strong Research and Development organization PGS has developed its own advanced processing system called Cube Manager which is deployed for both Onshore and Marine operations in strategically located centers around the world. The use of proprietary imaging software coupled with integrated visualization holoSeis, helps to reduce the risks in exploration and production.

As of March 31, 2005, PGS operates twelve land-based seismic data processing centers, with the largest centers being located in Houston, London, Lysaker, Cairo, Rio de Janeiro, and Perth.

Worldwide MC3D library

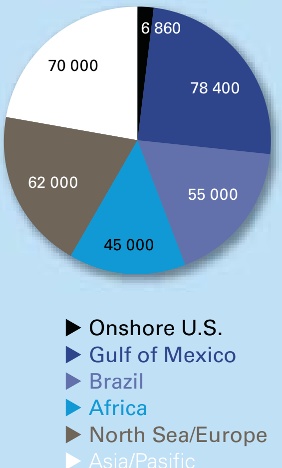
PGS owns a significant library of marine multi-client data in most of the major oil and natural gas basins of the world, including the Gulf of Mexico, the North Sea, offshore West Africa, offshore Brazil and the Asia Pacific region. PGS continues to build and market the multi-client data library, but also intends to acquire multi-client data in additional geographic areas from time to time.

PGS' multi-client data is marketed primarily through the Company's own sales organization.

PGS worldwide multi-client 3D library is approximately 320,000 square kilometers.

Sqkm of data by region

(total Multi-client Library)



Onshore

PGS' Onshore business consists of all of the Company's seismic acquisition operations on land and in very shallow water and transition zones, and includes an onshore multi-client library.

Business

PGS Onshore conducts contract onshore and transition zone seismic acquisition throughout the world and operated between five to seven crews during 2004. Onshore also has its own onshore multi-client library, which is located entirely in the United States. The Company's high channel count crews, modern equipment, including desert and arctic environmental specific operating gear, and experienced technical staff secure the highest efficiency combined with the best data quality.

Onshore has demonstrated market leading seismic service performance operating seismic crews in five terrain types:

- Desert
- Arctic
- Jungle & Swamp
- Highland & mountaintop
- Transition Zone

As of March 31, 2005, PGS had six crews conducting activities in the United States, Canada, Mexico and Venezuela.

Competitive advantage

Equipping our highly experienced personnel with fully compatible, state of the art recording electronics allows PGS to deploy on average more channels per crew than other companies. PGS offers traditional 3D and HD3D℠ acquisition with the highest efficiency. Hands-on experience executing HD3D℠ surveys and experienced technical staff, secure optimal survey design and high quality data.

Proactive social development programs have created a competitive advantage in Mexico, Ecuador and Bangladesh.

Market position

In the market for onshore seismic services, PGS is a medium sized player among a large number of both regional and global players. Competition and strengths and weaknesses vary significantly from region to region. New entrants to the market, including, among others, Chinese companies, play a significant role, especially in Asia.

Key figures Onshore (in millions of dollars, except head count)	2004 (US GAAP)	2003* (US GAAP)	2002 (US GAAP)
Revenues	133.2	150.4	118.7
Cost of sales, SG&A and R&D	97.8	93.2	103.5
Adjusted EBITDA	35.4	57.2	15.2
Depreciation and amortization	39.9	35.7	28.4
Other operating (income) expense, net	0.0	0.3	2.6
Impairment of long-lived assets	0.0	5.1	5.9
Operating profit	(4.5)	16.1	(21.8)
Total assets	90.5	117.4	119.5
Head count	1 011	1 479	1 828

** Combination of successor and predecessor*


PGS Onshore

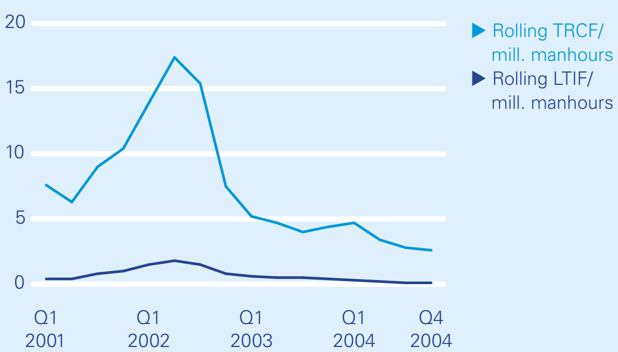
2004 Operational performance

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

Onshore continued acceptable operating performance in 2004 building on strong project execution and management. The activity level in domestic U.S. was high throughout the year and a third crew was added to this operating area.

At December 31, 2004, our order backlog for contract seismic acquisition was $66 million for our Onshore segment compared with $111 million at December 31, 2003.

PGS Onshore Safety Statistics Q1-2001 to present



2004 HSE Performance

Onshore operations recorded a Lost Time Incidents Frequency of 0.36 incidents per million man hours and a Total Recordable Case Frequency of 2.85 incidents per million man hours during the year. Five Lost Time Incidents were reported in 2004.

Outlook

In 2005 we will continue our focus on markets where we can compete most effectively. The full year activity level will be similar to that in 2004, building on an expected start-up of a significant transition zone project in Nigeria and expected contract awards for crews in South America.

We expect capital expenditures in Onshore to increase to above $10 million in 2005 as we make investments in equipment within certain areas. In 2004, our capital expenditures in Onshore were $1.4 million.

Onshore Multi-Client Library

PGS Onshore, Inc. has a multi-client data library which covers a wide range of terrain, entirely in the United States, from shallow water 3D data images in the Texas Gulf Coast to HD3D℠ data in the Alaskan Foothills. PGS Onshore is expanding the multi-client library in the U.S. mid-continent.

Production

PGS is the largest contractor operator of FPSO vessels in the North Sea, measured by production capacity and number of vessels. Through Production PGS owns and operates four harsh environment FPSOs with a combined production capacity of 339,000 barrels of oil per day and a crude oil storage capacity of one million barrels. Production has a long, proven track record in operating FPSOs in one of the harshest environments in the world.

Business

An FPSO is a ship-shaped mobile production unit that produces, processes, stores and offloads oil. The units can also re-inject or export natural gas from offshore fields. The FPSO fleet consists of the four vessels *Ramform Banff*, *Petrojarl I*, *Petrojarl Foinaven* and *Petrojarl Varg*. All the vessels are double hulled, rated for harsh environments and capable of working in fields with widely differing production characteristics, sizes and water depths. PGS also operates two shuttle tankers: *Petronordic* and *Petroatlantic*, and one storage tanker.

PGS Production has its head office in Trondheim, Norway, from where most of its operations are managed. It also has an operations office in Aberdeen, Scotland.

Market position

PGS is the market leader in operating contractor owned FPSOs in the UK and Norwegian sectors of the North Sea. The demand for these services is highly dependent on specific oil and gas development projects for small to medium sized oil fields.

2004 Operational performance

Production revenues for 2004 increased $2.9 million compared to 2003. *Petrojarl Foinaven* and *Petrojarl I* revenues declined primarily due to natural decline in field production.

The production on *Petrojarl I* was shut down from September 12 to October 29 due to a labor conflict on the Norwegian Continental Shelf (NCS), while production levels on *Ramform Banff* improved in the latter part of 2004 due to the tie in of one well from the Kyle field and development work on Banff field wells.

Revenues from *Petrojarl Varg* increased primarily due to increased production, despite a shut down for approximately two weeks in October related to a labor conflict on the NCS and damage to the main production riser that reduced production from November 5, 2004 through the end of the year. The field returned to normal production after a successful installation of a new riser on March 9, 2005.

Key figures Production (in millions of dollars, except head count)	2004 (US GAAP)	2003* (US GAAP)	2002 (US GAAP)
Revenues	298.2	295.3	306.6
Cost of sales, SG&A and R&D	175.9	165.0	150.3
Adjusted EBITDA	122.3	130.3	156.3
Depreciation and amortization	44.6	51.5	71.0
Other operating (income) expense, net	0.0	0.0	0.0
Impairment of long-lived assets	0.0	0.3	332.0
Operating profit	77.8	78.4	(246.6)
Total assets	710.5	790.3	1 168.6
Head count	501	515	520

** Combination of successor and predecessor*


ARCO

2004 HSE performance

PGS Production achieved excellent HSE performance in 2004, with no reported Lost Time Incidents – the first year ever in PGS Production's history. For 2004 the Total Recordable Incident Frequency was 1.7 per million man hours.

On November 4, 2004 *Petrojarl I* passed the milestone "three years without Lost Time Incidents". A lot of hard work is behind this achievement, which includes among others, excellent work procedures, campaigns, well coordinated and experienced crews, and an involved safety committee, management and land-based organization. As with all units, PGS Production works proactively with HSE, and this is one of the underlying reasons for having achieved three injury-free years. Production is proud of this milestone but at the same time stays focused on their track record by stressing HSE at all times.

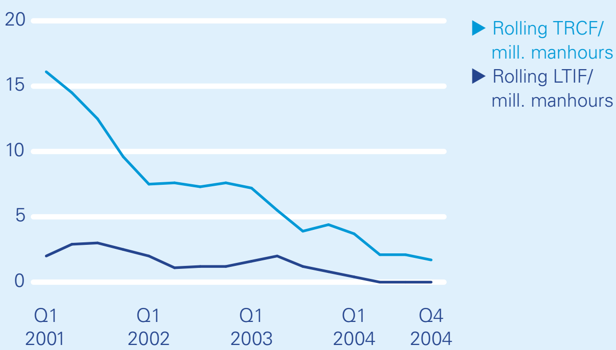
Exemplary environmental performance is essential for the success of the business. As a company PGS also recognizes the responsibility to contribute to a sustainable environmental development. Petrojarl Foinaven gained its ISO 14001 certificate in 1998, since then, FPSOs shuttle tankers and both offices in PGS Production have all been certified to the same environmental standard.

Outlook

In 2005 we expect that the total oil production from our four FPSOs will be in line with 2004 levels. We expect increased operating costs due to increased maintenance costs as the time since deployment of the FPSOs on their respective fields is increasing and due to a weakened U.S. dollar as compared to 2004.

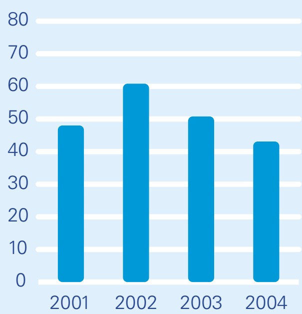
We expect capital expenditures in Production in 2005 to continue at a low level because our FPSOs are not expected to have substantial replacement needs through 2005 and we expense maintenance expenditures. In 2004, the capital expenditures in Production were $1.0 million.

PGS Production Safety Statistics Q1-2001 to present



Production – statistics

Million barrels produced



PGS's Production Vessels

Petrojarl I (1)

Petrojarl I is currently deployed on the Glitne field in the Norwegian North Sea on a multi-year contract for Statoil. Based on production estimates filed by the operator, PGS expects production under the contract to continue into 2007.

Since commencing operations in 1986, the FPSO has serviced ten fields and conducted over 1,300 offloadings to shuttle tankers without a reportable environmental incident.

Petrojarl Foinaven (2)

The vessel is on a contract to a consortium of field co-operators led by Britoil, a subsidiary of BP, for production on the Foinaven field in the Atlantic west of the Shetland Islands. *Petrojarl Foinaven* has successfully weathered severe North Atlantic storms. The Foinaven contract is not limited as to time. BP may terminate the contract with a minimum of two years' notice. PGS currently expects that the vessel will remain on the field for a substantial period.

Petrojarl Varg (3)

Petrojarl Varg, produces the Varg field on the Norwegian Continental shelf of the North Sea under a contract with the licence owners of Production License 038. The vessel is the newest addition to PGS' fleet of high specification FPSOs. The purpose-built, double-hulled vessel was acquired from Saga Petroleum.

In connection with the recent disposal of Pertra, Talisman and PGS have agreed to an option for Talisman to extend the term of the charter and operating agreements for *Petrojarl Varg* until 2010. The option is exercisable until February 1, 2006, and if exercised the license owners will be obligated to pay PGS $22.5 million and to guarantee a minimum of $190,000 per day as compensation for the use of *Petrojarl Varg*.

Ramform Banff (4)

The *Ramform Banff* began producing the Banff field in 1999 and is currently in production for the field operator Canadian Natural Resources (CNR). The Banff field is located in the UK sector of the North Sea. Under the existing contract with the field operator, PGS will continue to produce the Banff field with the *Ramform Banff* until the end of the life of the field.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Pertra

Pertra was established in late 2001, to secure continued employment of the *Petrojarl Varg*. On February 1, 2005, PGS announced the sale of Pertra AS to Talisman Energy (UK) Limited ("Talisman"). The transaction was completed on March 1, 2005.

Disposal of Pertra

Under the agreement Talisman paid cash of approximately $155 million for 100% of the Pertra shares. PGS expects to recognize a gain from the sale for financial reporting purposes of approximately $140 million. In addition, as a part of the transaction, Talisman has agreed to share with us (on a post petroleum tax basis), on a 50/50 basis for each of 2005 and 2006, their revenues from production from their interest in the Varg field in excess of $240 million.

2004 Operational Performance

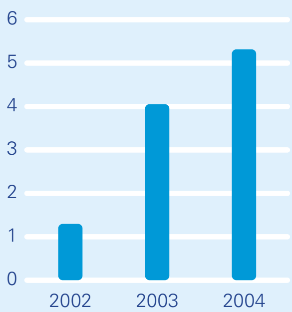
Pertra revenues for 2004 increased $62.5 million compared with 2003 primarily due to increased production of oil. Pertra's net oil production in 2004 was 5.3 million barrels compared to 4.1 million barrels in 2003 and 1.3 million barrels in 2002.

Pertra had significant drilling activity in 2004, with a rig working throughout the entire year. In total, five development wells were completed on the Varg field. In addition, one dry exploration well was drilled on the "Villmink" prospect in PL 038.

In the fourth quarter production was negatively affected by a shut down from October 13 to October 26, caused by a labor conflict on the NCS, and then damage of the main production riser on November 5, limiting production to a daily maximum of approximately 15,000 barrels for the remaining of 2004.

Pertra – statistics

Million barrels produced



Key figures Pertra (in millions of dollars, except head count)	2004 (US GAAP)	2003* (US GAAP)	2002 (US GAAP)
Revenues	184.1	121.6	32.7
Cost of sales, SG&A and R&D	117.0	76.0	24.2
Adjusted EBITDA	67.1	45.6	8.5
Depreciation and amortization	39.0	31.6	12.7
Operating profit	28.1	14.0	(4.2)
Total assets	120.6	67.1	75.6
Head count	16	5	6

** Combination of successor and predecessor*

Reservoir

PGS Reservoir is a leading international provider of sub-surface technical and commercial expertise. PGS is internationally recognized for ultra-large scale regional interpretation projects – PGS MegaSurveys – and for the ability to provide a complete asset and operations management service.

PGS Reservoir is an integrated geoscience and petroleum engineering consultancy. All of the technical staff draw upon many years relevant experience within the oil industry, mostly from international operating oil companies. Much of the project work is carried out in integrated multi-disciplinary teams tailored to meet the requirements of each project. The teams is comprised of professional geoscientists, engineers and petroleum economists.

PGS Reservoir offers services within the whole value chain from licensing of new acreage, exploration, appraisal, field development, production, asset valuation and from small evaluations to complete asset management. PGS Reservoir can also provide technical experts to supplement the customers own resources.

PGS work for a client base that includes independent and major oil companies, governments, financial and legal institutions.

Through these projects the company has gained a depth and breadth of expertise in a diverse range of exploration and production problems worldwide.

Corporate Governance in PGS

PGS is committed to maintaining high standards of corporate governance. We believe that effective corporate governance is essential to the well being of the Company and establishes the framework by which we conduct ourselves in delivering services to our customers and value to our shareholders.

PGS is registered in Norway as a public limited liability company and the Company's governance model is built on Norwegian corporate law. PGS also adheres to requirements applicable to foreign registrants in the U.S. where the Company's American Depositay Shares (ADS) are publicly traded, including the New York Stock Exchange listing standards, and requirements of the SEC. In addition PGS implements corporate governance guidelines beneficial to its business.

The PGS corporate governance principles are adopted by the Board of Directors. Below is a summary of PGS' principles. The articles of association of PGS ASA, in addition to full versions of the PGS Corporate governance principles, the rules of procedures for the Board of Directors, the Audit Committee charter, the Remuneration Committee charter and the Code of Conduct are available on the Company's website (www.pgs.com).

Code of Conduct and Core Values

PGS has adopted a Code of Conduct that reflects our commitment to our shareholders, customers and employees to conduct our business with the utmost integrity. PGS' Code of Conduct and Core Values are presented on page 5 of the annual report and are available in full versions on www.pgs.com.

Business

PGS' business is defined in the articles of association as:

"The business of the Company is to provide services to and participate and invest in energy related businesses."

The goals and strategies for the two business units in PGS are presented on page 4 of this annual report.

Equity and dividends

At December 31, 2004 the consolidated shareholder's equity of PGS was $222.9 million (US GAAP). In March 2005 the Company sold its wholly-owned oil company subsidiary, Pertra. The sale will result in a gain in excess of $140 million. In April 2005 the Company called $175 million of its 8% Senior Notes.

Further strengthening of financial flexibility is a key priority of PGS. Consequently, PGS expects to use its cash flows to develop its core businesses and maintain/improve financial flexibility.

PGS does not expect to pay ordinary dividends to shareholders in the next two to three years. We are not allowed to pay dividends under our loan agreements until our 8% Senior Notes are repaid, and, at year-end 2004, the parent company does not have free equity that, under Norwegian corporate law, can be distributed as dividends.

Equal treatment of shareholders and transactions with related parties

PGS has one class of shares. In the Company's General Meeting each share has one vote. The Board of Directors is committed to equal treatment of shareholders in all respects. When applicable, transactions in our shares should be carried out through the stock exchange.

An owner with shares registered through a custodian approved pursuant to Section 4 - 10 of the Norwegian Public Limited Companies Act has voting rights equivalent to the number of shares which are covered by the custodian arrangement provided that the owner of the shares, within two working days before the General Meeting provide PGS with his name and address together with a confirmation from the custodian to the effect that he is the beneficial owner of the shares held in custody.

Transactions between the Company and related parties shall be conducted at market values. Material transactions will be subject to independent valuation by third parties.

Freely transferable shares

The shares are freely transferable except that an acquisition by assignment shall be contingent upon approval by the Board of Directors of the Company, which cannot be withheld without reasonable grounds.

General Meetings

Through the General Meetings the shareholders exercise ultimate authority in PGS and elect the members of the Board of Directors.

Notice of the General Meeting including all pre-material, is generally given at least four weeks in advance to the shareholders or their depositary bank. For ADS holders a record date is set approximately 5 weeks prior to the Annual General Meeting. The calling notice is circulated by the depositary bank to ADS holders as of the record date.

The notice convening an Extraordinary General Meeting shall be given at least two weeks before the meeting if the holding of the meeting is demanded in writing by the independent auditor or shareholders representing at least 5% of the share capital. Shareowners who wish to take part in a General Meeting must give notice to PGS by the date stated in the calling notice, which date must be at least two working days before the General Meeting.

To vote at the General Meeting, in person or by proxy, a shareholder must be registered with the Norwegian Registry of Securities. Holders of ADS may vote the shares underlying the ADSs by: (a) having the underlying shares transferred to an account with the Norwegian Registry of Securities in the name of the holder, (b) attending the meeting as a shareholder, by providing their name and address, and a confirmation from Citibank, depositary for the ADS, to the effect that they are the beneficial owner of the underlying shares, or (c) authorizing Citibank to vote the ADS on their behalf.

A General Meeting shall be chaired by the chairman of the Board of Directors.

Nomination committee

PGS did not have a nomination committee at December 31, 2004.

The Board of Directors will propose for the 2005 Annual General Meeting to establish and elect a nomination committee. The proposal will suggest that the nomination committee is included in the Company's articles of association. The nomination committee's duties should be to propose candidates for election to the Board of Directors, and to propose the fees to be paid to the members of the Board.

Board of Directors – composition and independence

According to the articles of association the Board of Directors of PGS shall have from three to eight directors. The Board of Directors has adopted internal rules of procedures that establish in more detail its role and responsibilities, including:

- directors' qualifications
- qualification of a majority of the Board of Directors and all of the members of the Audit and Remuneration Committees as "independent directors"
- annual review and determination of the independence of each director

No member of the Board shall be an executive of PGS. Directors cannot perform paid consultancy work for PGS. In addition, a majority of the Board shall be "independent" in accordance with the listing standards of the New York Stock Exchange. No director will qualify as "independent" unless the Board of Directors affirmatively determines that the director has no material relationship with the Company.

Until October 16, 2005, any election of new directors and amendment of the instruction to the Board concerning approval of major transactions shall require the approval by more than two thirds of the votes cast as well as of the share capital which is represented at the General Meeting. Subsequent to October 16, 2005, the majority rule pursuant to the Norwegian Public Limited Companies Act § 5 – 17 shall apply to such actions.

The current Board of Directors

As of December 31, 2004 the Board of Directors consisted of seven shareholder representatives and two alternate representatives. In the event of the absence of a director, an alternate director may be requested to take part in a Board meeting. Neither the CEO nor any other member of the executive management is a director of the Board. The current members of the Board of Directors are presented on page 26 and 27 of this annual report and on www.pgs.com.

The work of the Board of Directors

In accordance with Norwegian corporate law, the Board of Directors has overall responsibility for management of the Company, while the CEO is responsible for day-to-day management. The Board supervises the CEO's day-to-day management and the activities of the Company in general. It is also responsible for ensuring that appropriate steering and control systems are in place. A minimum of six board meetings shall be held each year. The CEO shall, in agreement with the chairperson of the Board, annually present a meeting calendar covering the next calendar year to the Board for approval. The meeting calendar shall be structured so as to allow the Board to deal with its responsibilities in a systematic and orderly fashion. In 2004 the Board of Directors had 17 meetings.

The Board of Directors has adopted internal rules of procedures which establish in more detail its role and responsibilities, in relation to the management and supervision of the Company. The rules emphasize among other things the Board's responsibility to decide PGS' financial targets and determine the overriding strategy for PGS in collaboration with the CEO and the Group Leader Team, and to approve the business plans, budgets and frameworks. In its supervision of the business activities of PGS, the Board will seek to ensure that there exist satisfactory routines for follow-up of principles and guidelines required by the Board in relation to ethical behaviour, conformity to law, health, safety and environment, and social responsibility. The rules also require provision for an annual self-evaluation of the Board to determine whether the Board and its committees are functioning effectively. The tasks and duties of the CEO vis-à-vis the Board are outlined in the rules along with the tasks and duties of the chairperson of the Board. The Board shall have a vice-chairperson to chair the Board in the chairperson's absence. The full version of the rules of procedures for the Board of Directors is available on www.pgs.com.

The governance structure of PGS is organized as described below:

- The Board is responsible for the development and supervision of the business activities of PGS.
- The Board has established Audit and Remuneration Committees to assist in organizing and carrying out its responsibilities. Full versions of the Audit Committee charter and the Remuneration Committee charter are available on www.pgs.com.
- The Board of Directors appoints the CEO.
- The CEO is responsible for the day-to-day management of the Company's activities.
- The CEO has organized the Group Leader Team and the Disclosure Committee to further assist in discharging the CEO's responsibilities.
- The Board, along with the CEO, is committed to operating PGS in an effective and ethical manner in order to create value for the shareholders. PGS's Code of Conduct requires PGS management to maintain an awareness of the risks to the Company in carrying out its business strategies and not to put personal interests ahead of or in conflict with the interests of the Company.
- The CEO, under the oversight and guidance of the Board and its Audit Committee, is responsible for ensuring that the financial statements of the Company fairly present in all material respects its financial condition and results of operations and that the Company makes timely disclosures needed to assess the financial and business soundness and risks of PGS.

Board Committees

The Audit Committee has three members elected by and among the members of the Board. Its function is to; assist the Board in its oversight of the integrity of the financial statements of PGS; the independent auditor's qualifications, independence, and performance; the performance of the internal audit function; and compliance with legal and regulatory requirements. The Audit Committee is composed of members that satisfy the SEC's and the NYSE's independence requirements.

The Remuneration Committee consists of two members who are elected by and among the members of the Board. The function of the Committee is to assist with the matters relating to the compensation, benefits and perquisites of the Company's CEO and other senior executives.

The chairperson of a subcommittee shall ensure that the Board after every subcommittee meeting receives a report on the issues reviewed by the subcommittee, and that all matters before the subcommittee requiring the decision of the Board are placed on the agenda of the Board and that adequate documentation in support of a decision is provided to the Board.

In 2004 the Audit Committee had 15 meetings while the Remuneration Committee had seven meetings.

Remuneration of the Board of Directors and the executive management

The remuneration to the members of the Board of Directors is not linked to the Company's performance, but is based on participation in meetings, and is approved by the General Meeting annually. The Board Members shall not take on specific assignments for the Company in addition to their appointment as a Member of the Board.

The Remuneration Committee and the Chairman of the Board proposes the remuneration of the CEO. The remuneration is decided by the Board of Directors in a convened meeting.

At present, PGS has no share option schemes.

The remuneration of the Board of Directors, CEO and other executive officers is reported in note 31 to the consolidated N GAAP financial statements.

Information and communications

The Board of Directors is committed to reporting of financial and other information based on openness and taking into account the requirement for equal treatment of all participants in the securities market. As a listed company, PGS has to comply with relevant regulations regarding disclosure. Announcements that are made to comply with disclosure requirements are released through Oslo Stock Exchange's Company Disclosure System and through relevant channels in the US market. In addition, all announcements are available on the company's website www.pgs.com. PGS' IR policy comprises guidelines for the Company's reporting of financial and other information.

Take-overs

The Board of Directors will not seek to hinder or obstruct any take-over bids for the Company's activities or shares, or exercise mandates or pass any resolutions that obstruct take over bids that are put forward.

Auditor

The Audit Committee shall support the Board in the administration and exercise of the Board's responsibility for supervisory oversight of the work of the independent auditors, which shall keep the Audit Committee informed of all aspects of its work for the Company. This includes submission of an annual plan for the audit of the Company. Subject to the approval of the Board, the Audit Committee shall:

- pre-approve all auditing services and permitted non-audit services to be provided by its independent auditors and shall not engage the independent auditors to perform the specific non-audit services restricted by law or regulations; and
- to the extent it deems necessary or appropriate, retain and compensate independent legal, accounting or other advisors.

The independent auditor shall meet with the Board of Directors at least once a year in connection with the preparation of the annual accounts, and at least once a year present to the Board of Directors a review of PGS' internal control procedures. The auditor will be asked annually to confirm in writing that the auditor satisfies the requirements for independence. The auditor shall also provide the Board with a summary of all services in addition to audit work that have been undertaken for PGS. The remuneration paid to the auditor will be reported to the Annual General Meeting for approval.

US-listing matters

Re. the Audit Committee

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

Re. the Remuneration Committee

As a foreign private issuer in the United States, PGS is not required to publish the Remuneration Committee report required by applicable regulations of the U.S. Securities and Exchange Commission for U.S. domestic issuers.

Re. Nomination and Corporate Governance Committee

The listing standards of the New York Stock Exchange require U.S. listed companies to have a Nominating and Corporate Governance Committee to: (1) identify individuals qualified to become board members and to select, or to recommend that the board select, the director nominees for the next annual general meeting; (2) develop and recommend to the board a set of corporate governance guidelines applicable to the listed company; and (3) oversee the evaluation of the board and management. In accordance with Norwegian law and customary practice, the PGS Board of Directors, which is composed entirely of non-management directors, fulfills those responsibilities.

Re. Board composition and independence

If the Board of Directors includes a director who is not independent under New York Stock Exchange listing standards, the independent directors will meet in executive session at least once annually.

For purposes of determining a director's independence, a director will not be independent in accordance with the listing standards of the New York Stock Exchange if:

- the Board has not affirmatively determined that the director has no material relationship with the company (either directly or as a partner, shareholder or officer of an organization that has a relationship with the Company)
- the director is, or has been within the last three years, an employee of the Company, or an immediate family member is, or has been within the last three years, an executive officer of the Company
- the director has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $100,000 in direct compensation from the Company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service)
- the director or an immediate family member is a current partner of a firm that is the Company's internal or external auditor;
- the director is a current employee of such a firm;
- the director has an immediate family member who is a current employee of such a firm and who participates in the firm's audit, assurance or tax compliance (but not tax planning) practice; or
- the director or an immediate family member was within the last three years (but is no longer) a partner or employee of such a firm and personally worked on the Company's audit within that time
- the director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the Company's present executive officers at the same time serves or served on that company's compensation committee
- the director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the Company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million, or 2% of such other company's consolidated gross revenues.

The Board of Directors

Jens Ultveit-Moe (62)
Chairman (elected 2002)

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

Keith Henry (60)
Vice chairman (elected 2003)

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.

Claire Spottiswoode (52)
Board member (elected 2003)

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.

Francis Gugen (56)
Board member (elected 2003)

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

Harald Norvik (59)
Board member (elected 2003)

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.

Rolf Erik Rolfsen (64)
Board member (elected 2002)

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.

Anthony Tripodo (52)
Board member (elected 2003)

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.

Board committees

Under Norwegian law, decision-making authority may not be delegated by the Board of Directors to its committees or subcommittees.

The Board may, however, establish committees to assist it in discharging its responsibilities. PGS' Board of Directors has appointed two such committees: the Audit Committee and the Remuneration Committee. Further details on the Audit Committee and the Remuneration Committee are presented on page 24 of this annual report.

The Audit Committee currently consists of three members, Messrs. Gugen (chairman), Norvik and Tripodo. The Board of Directors has determined that the members of the Audit Committee are independent under applicable provisions of the Securities Exchange Act of 1934 and New York Stock Exchange listing standards.

The Remuneration Committee consists of Messrs. Henry (chairman) and Rolfsen. The Board of Directors has determined that the members of the remuneration committee are independent under applicable New York Stock Exchange listing standards.

PGS Group Leader Team

Svein Rennemo (57)

President and CEO

Svein Rennemo joined PGS in November 2002. Prior to joining PGS, he was a partner at ECON Management. From 1997 to 2001, Mr. Rennemo served as CEO of Borealis, one of the world's leading producers of polyolefin plastics, headquartered in Copenhagen, Denmark. From 1994-97 he was CFO and deputy CEO at Borealis. From 1982 to 1994, Mr. Rennemo filled various senior management positions with Statoil, among them CFO and President of Statoil Petrochemicals. He has served as macro economic policy analyst and advisor with the Central Bank and the Ministry of Finance in the Kingdom of Norway and with the OECD Secretariat in Paris. Mr. Rennemo earned a Master's Degree in economics at the University of Oslo in 1971. Mr. Rennemo is a non-executive board member of Dynea of Finland and Nutreco of the Netherlands.

Gottfred Langseth (38)

Senior Vice President and CFO

Langseth joined PGS as Senior Vice President and CFO in January 2004. He previously held the same position in Ementor ASA (Merkantildata) from 2000 to August 2003, and has served as SVP Finance/Control for the Norwegian offshore company Aker Maritime from 1997 to 2000 and in a managerial position at Arthur Andersen, Norway from 1991 to 1997. Mr. Langseth qualified as Norwegian State Authorized Public Accountant in 1991 and has an MBA from the Norwegian School of Economics and Business Administration.

Rune Eng (43)

President PGS Marine Geophysical

Before joining PGS in 1997, Mr. Eng held different positions in Fugro-Geoteam, including a board position in Sevoteam, a Russian-Norwegian joint operating company. Mr. Eng joined PGS as Area Manager Scandinavia and was then named President Europe, Africa and Middle East in 2000. Rune Eng was appointed President, PGS Geophysical in August 2004. He has a Bachelor Degree in applied Geophysics from University of Oslo and a Master of Science degree from Chalmers University of Technology in Sweden.

Eric Wersich (42)

President PGS Onshore

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.

Sverre Skogen (48)

President PGS Production

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. Mr. Skogen has previously served as President and CEO of Aker Kværner AS, Oil & Gas Division from March 2002 to January 2003, President and CEO of Aker Maritime ASA from May 1997 to March 2002, and Executive Vice President of Aker RGI from January 1997 to May 1997. He was founding partner of Terramar Prosjektledelse, and helped establish TerraMar Informasjonssystemer in 1993, which he headed until 1997. During the 1980's he held various positions in Norwegian Petroleum Consultants, the engineering contractor for a number of large developments on the Norwegian continental shelf. Sverre Skogen has an MSc in Construction Management, a MBA in Business Administration and a BSc in Civil Engineering, all from the University of Colorado.

Anthony Ross (Diz) Mackewn (57)

Group Senior Vice President Geophysical

Diz Mackewn joined PGS as Technology Director of PGS Nopec in 1993. He transferred to PGS Exploration in 1996, where he served as Managing Director of PGS Exploration UK Ltd. In 1999 he was named President Exploration EAME and in 2001 became President of PGS Geophysical Services. In 2003 Mr. Mackewn was named President of PGS Marine Geophysical and was recently appointed Group Senior Vice President, 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.

Espen Klitzing (41)

Senior Vice President Business Development and Support

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

Other Corporate Management

Erlend Bakken
General Counsel

Terje Bjølseth
Vice President Global Human Resources

Ola Bøsterud
Vice President Group Communications

Jerry Courtney
Vice President Compliance

Ole-Andreas Isdahl
Group Vice President HSE

Sam Morrow
Senior Vice President Finance and Treasurer

Christin Steen-Nilsen
Vice President Chief Accounting Officer

HSE in PGS

PGS has in 2004 systematically achieved high quality performance within the area of HSE. The efforts made manifest the Company's focus on continuous improvement, which produced the excellent HSE results for 2004. Our systems, staff and base of competence is the key to this success, and our future focus will be characterized by further investments in these resources.

Our HSE results are effectively supporting our efforts in maintaining our position as the market leader.

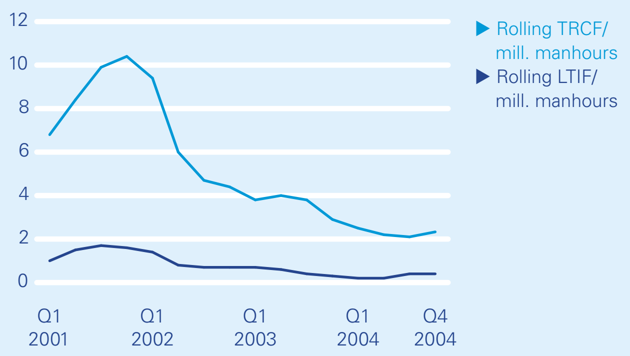
Achievements in 2004

- *Petrojarl Varg* ranked as one of the three safest offshore installations on the NCS by The Norwegian Petroleum Safety Authority (PSA)
- *Ramform Valiant* achieved three million manhours LTI-free (over six years without Lost Time Incidents)
- First year ever without lost time incidents in Production
- Implemented best available technology (BAT) to reduce discharges to sea within our seismic operations
- Production was ISO 14000 (international standard for environmental management) certified in 2004.
- Production (shuttle tankers) was certified by International Ships and Port Security Code (ISPS)
- Social responsibility program launched successfully by PGS Onshore
- Pertra headed up the oil industry's annual full scale oil contingency exercise in cooperation with NOFO (Norwegian Clean Seas Association for Operators) with great success.

Our HSE goals for 2005

- Further strengthen and improve our management systems, our base of competence and our ability to drive improvement processes
- Improve our capability to identify and implement best practice to ensure that learning and experience transfer takes place within our organization.
- Develop our network, and ensure that we learn from those representing the forefront within HSE

PGS Total Statistics Q1 2001 to present



- Further simplify our systems and routines to improve their effect on the operational levels
- Develop as a learning organization and further invest in our human assets to improve our performance and position in the world markets.
- Further reduce and eliminate risk related to our activities and operations

Delivery of strong results in 2004

The 2004 high performance HSE results are produced through:

- Clear goals
- Top management attention and commitment to HSE
- Leadership in HSE
- Organizational commitment
- A well developed management system
- Competent staff
- Established improvement processes

We believe that we can improve, and we continue to strive for even better results. Our assets in this effort are seen to be:

- Experience
- Competence
- Structure
- Simplicity

Our efforts to improve

Throughout 2004 PGS maintained a strong focus on improvement processes.

Industry expectations for continuous improvement are influencing all our activities. Our improvement processes are documented in our Management Systems and will provide an adequate description of how we actually perform our day to day business.

Our base of competence represents an important criteria for success and is an important element in the process of managing our business processes and in achieving our goals and objectives. Our industry is continuously improving, and we have to respond to increased focus on sustainability, risk reduction and management of change.

In 2004 we have improved by obtaining certification and compliance with important industry standards like ISPS, IAGC, OGP and the ISO 14000. We have gained important knowledge from these processes, and we will continue to share this knowledge to enable development of PGS as a whole.

Guidelines provided by our Core Values assist us in maintaining focus on high HSE performance and our ethical norms. We strive to maintain and improve quality through maintenance, development and sharing of our competence. In 2004 we have done that by holding a series of Core Value seminars where we share and discuss our challenges.

Incidents in 2004

Pertra caused in 2004 3,000 liters of oil to be discharged to sea. The incident was caused by a fatigue in a flexible production riser on the *Petrojarl Varg*. The incident did not cause any major damage to the environment or wild life at sea.

In March 2004 we had a minor gas explosion onboard the *Petrojarl Varg*. The incident did not cause any harm to people, the environment or our assets.

PGS had a total of 9 lost time incidents in 2004, none which were of a serious nature.

The PGS Share

In December 2004 PGS' American Depositary Shares ("ADS") were re-listed on the New York Stock Exchange ("NYSE"). The NYSE-listing symbolizes the completion of the PGS financial restructuring.

PGS' ordinary shares are primary listed on the Oslo Stock Exchange under the symbol "PGS" - nominated in Norwegian kroner ("NOK"). PGS' ordinary shares have traded on the Oslo Stock Exchange since August 1992. PGS' shares are also traded on the New York Stock Exchange in the form of American Depositary Shares, or ADSs, under the symbol "PGS", nominated in U.S. dollars. Each ADS represents one share. The market value of PGS by December 31, 2004 was NOK 7,570 million ($1,241 million).

Dividend policy

PGS does not expect to pay ordinary dividends to shareholders in the next two to three years.

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.

Information and communications

The Board of Directors is committed to reporting financial and other information based on openness taking into consideration the requirement for equal treatment of all participants in the securities market. As a listed company, PGS has to comply with relevant regulations regarding disclosure. Announcements that are made to comply with the duty of disclosure are released through Oslo Stock Exchange's Company Disclosure System and through relevant channels in the US market. In addition, all announcements are available on the company's website www.pgs.com. PGS' IR policy comprises guidelines for the Company's reporting of financial and other information.

Share performance

On Oslo Stock Exchange the PGS share was priced at NOK 260 in the beginning of 2004 and at NOK 378.50 at the end of 2004, an increase of 46 per cent. The Oslo Stock Exchange Benchmark index, OSEBX, rose by 38 per cent over the same period, while the energy index, OSE10GI, rose by 41 per cent. The highest closing price of NOK 385 for the PGS share was attained on December 27, while the low closing price for the year was NOK 245 on May 14. The average share price was NOK 302.05.

An average of 108,893 shares was traded on Oslo Stock Exchange per trading day in 2004, compared with an average of 238,072 shares from November 6, 2003 to year end 2003. The total traded volume was 8.57 million shares in the period from November 6, 2003 to year end 2003 and 27.5 million in 2004. The traded volume on Oslo Børs corresponds to a turnover ratio of 138%.

In the American over-the-counter (OTC) market the PGS ADS opened at $36.50 on the first day of trading in 2004. The ADS price ended at $62.06 at the year end, an increase of 70 per cent. The Standard & Poor's 500-index rose by 6 per cent over the same period. The highest closing price of $62.25 was attained on December 15, while the low closing price for the period was $33.50 on May 20. The average ADS price was $44.54. On December 17, 2004, our ADSs were relisted on the NYSE.

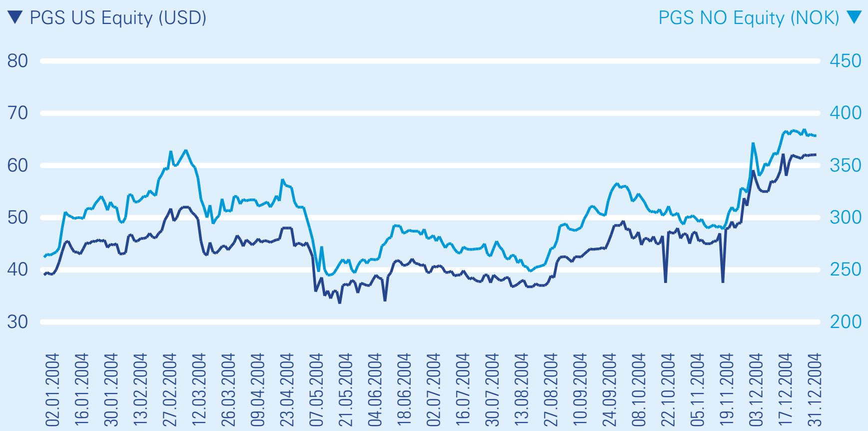
An average of 52,658 ADSs was traded per trading day in 2004, compared with an average of 67,632 shares from November 6, 2003 to year end 2003. The total traded volume on NYSE in the period was 13.3 million ADSs.

Shareholders and voting rights

At the end of 2004, PGS had 2,952 registered shareholders.

All shares are entitled to one vote. It is, however, a requirement of Norwegian legislation that one can only vote for shares registered in one's name. 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 regis-

PGS Share Price



ter maintained at Verdipapirsentralen ("VPS"), the Norwegian centralized register of securities, not later than at the date of the General Meeting.

Owners of ADSs can vote by surrendering their American Depository Receipts, 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.

International Financial Reporting Standards ("IFRS")

Effective January 1, 2005 publicly traded companies in EU and EEA countries are required to report financial statements based in IFRS. Several EU/EEA countries, including Norway, have established transition rules allowing companies that are listed for public trading in the U.S., and therefore, have prepared complete financial statements under US GAAP, at least from and including 2002, to defer adopting IFRS reporting until January 1, 2007. Based on its listing and reporting history, PGS has concluded that the transition rules apply to the Company and plans to defer IFRS reporting until January 1, 2007.

20 largest shareholders as of 15 April, 2005

Shareholder		Shares	%	Country	Type
1	Citibank N.A.*	4 232 444	21.1%	USA	ADR
2	State Street Bank & Co.	1 053 124	5.2%	USA	Nominee
3	Umoe Invest AS	1 012 444	5.1%	NOR	Ordinary
4	Morgan Stanley & Co.	718 244	3.5%	GBR	Nominee
5	Morgan Stanley And Co.	645 636	3.2%	GBR	Nominee
6	The Northern Trust Co.	635 916	3.1%	GBR	Nominee
7	Morgan Stanley & Co.	590 794	2.9%	GBR	Nominee
8	Goldman Sachs & Co.	532 688	2.6%	GBR	Nominee
9	JP Morgan Chase Bank	473 273	2.3%	GBR	Nominee
10	Euroclear Bank S.A.	432 202	2.1%	BEL	Nominee
11	Odin Norden	393 960	1.9%	NOR	Ordinary
12	Vital Forsikring ASA	313 490	1.5%	NOR	Ordinary
13	Mellon Bank	293 003	1.4%	USA	Nominee
14	J P Morgan Chase Bank	231 350	1.1%	GBR	Ordinary
15	Odin Norge	226 331	1.1%	NOR	Ordinary
16	The Northern Trust Co.	215 507	1.0%	GBR	Nominee
17	VPF DnB NOR Norge	214 440	1.0%	NOR	Ordinary
18	Odin Offshore	205 000	1.0%	NOR	Ordinary
19	BNP Paribas Sec.	204 071	1.0%	FRA	Nominee
20	Goldman Sachs Int'l	202 157	1.0%	GBR	Nominee
20 Largest		12 826 074	63.1%		
Total		20 000 000	100.0%		

** Administrator of the ADS program.*

PGS Shareholdings per region as of 15 April, 2005

Country	Holders	Shares	% of Total
USA	87	6 447 026	32.2%
United Kingdom	94	6 278 003	31.4%
Norway	2 647	5 004 310	25.0%
Other Countries	190	2 270 661	11.4%
Total	3 018	20 000 000	100%

Words and Definitions

Seismic data

Seismic data is used by oil and natural gas companies to help them find oil and gas and to determine the size and structure of known reservoirs and to help them manage the production of reservoirs. Oil and natural gas companies also use this information in evaluating whether to acquire new leases or licenses in areas with potential accumulations of oil and gas. The data is also used in selecting drilling locations, in modelling oil and gas reserves and in managing producing reservoirs.

Acquiring seismic data – different technologies

- 2 dimensional (2D) - recorded and processed in a single line direction
- 3 dimensional (3D) - numerous closely spaced lines providing a high spatial sampling of data
- High Density 3 dimensional (HD3D℠) - 3D data with significantly higher trace densities. HD3D℠ allows for improved resolution of the subsurface and higher quality images of the reservoirs.
- 4 Component (4C) – also referred to as seafloor seismic. The recording cables are placed directly on the ocean floor. This method provides more information about the rock layer beneath the seabed.
- 4 Dimensional (4D) - 3D surveys acquired at different times (also called time lapse seismic) over the same area to evaluate subsurface geophysical conditions that may change over time due to depletion from production of reservoir fluids
- Ocean Bottom Cable (OBC) - both 2D and 3D data recorded and processed from laying equipment on the ocean floor

Contract Operations

In contract operations clients direct the scope and extent of the survey and retain ownership of the data obtained. Contracts for seismic data acquisition, which are generally awarded on a competitive bid basis, may include both a day-rate and a production rate element. Under these contracts, the customer normally assumes primary responsibility for interruption of acquisition operations due to factors that are beyond our control, including weather and permitting. Contracts may also be awarded on a turnkey basis. With turnkey contracts, revenue is based upon the number of seismic lines or square kilometers of seismic data collected and PGS often bears some or all of the risk of business interruption, due to causes beyond our control such as, among others, weather and permitting.

Multi-Client Operations

In multi-client operations clients license seismic data on a non-exclusive basis. This is typically less expensive on a per unit basis than acquiring the seismic data on a contract exclusive basis. From the perspective of PGS the multi-client seismic data is more cost effective to acquire and may be licensed a number of times to different clients over a period of years. As a result, multi-client seismic data has the potential to be more profitable than contract data. However, when PGS acquires multi-client seismic data the Company assumes 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.

Prefunding and late sales

In multi-client operations, PGS makes initial licenses of data prior to project completion, referred to as prefunding. All further licenses are referred to as late sales. A substantial portion of these late sales are made in connection with acreage license round activity in those regions where PGS has a data library. In most areas outside the Gulf of Mexico 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, both the total amount and the timing of late sales can be difficult to forecast accurately, with potentially significant revenue swings from quarter to quarter and from year to year.

Multi-Client Library

PGS owns a significant data library of marine multi-client data in most of the major oil and gas basins of the world, including the Gulf of Mexico, the North Sea, West Africa, Brazil and the Asia Pacific region. The PGS Onshore multi-client library is entirely in North America.

FPSO

An FPSO is a ship-shaped mobile production unit that produces, processes, stores and offloads oil. The units can also reinject or export natural gas from offshore fields. FPSO systems typically perform the same function as fixed oil offshore platforms in the offshore production of oil and natural gas, with the exceptions of drilling and heavy well maintenance. FPSO systems generally provide a number of advantages over fixed platforms, including capability of storing and offloading oil. They are suitable for a wide range of field sizes and water depths, are reusable on more than one developed reservoir and generally cost less and are easier to install and remove than fixed platforms.

Financial Review 2004

Petroleum Geo-Services

Financial Review

Overview

Our results of operations for the years 2004, 2003 (Successor and Predecessor) and 2002 are presented below in an expanded format that shows the primary components of and key drivers affecting our results of operations. Our consolidated statements of operations show separately the ten month period ended October 31, 2003 (Predecessor) and the two month period ended December 31, 2003 (Successor) as we emerged from Chapter 11 bankruptcy proceedings on November 5, 2003 and adopted fresh start reporting effective as of November 1, 2003. As indicated in the discussion of our results for 2003 below, Successor and Predecessor are in some areas combined for purposes of the discussion. Successor financial statements are prepared on the basis of fresh start reporting from November 1, 2003 and include changes in the carrying value of assets and liabilities and changes to certain accounting policies. For a more thorough description of the adoption of Fresh Start Reporting, see notes 1, 2 and 3 of the Consolidated Financial Statements.

In addition, the results of operations discussed below exclude 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 consolidated financial statements. The results of operations discussed below includes the results for Pertra, our oil and natural gas subsidiary that we sold in March 2005.

We present operating results below based on our four business segments in 2004 — 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 generated oil production revenues from its 70% interest in PL 038 in the Norwegian Sector of the North Sea.

Revenues

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

(In thousands of dollars)	Year Ended December 31, 2004	Year Ended December 31, 2003[1]	Year Ended December 31, 2002
Marine Geophysical			
Contract	$ 297 749	$ 350 724	$ 282 234
Multi-client pre-funding	30 535	49 697	100 326
Multi-client late sales	203 397	160 221	178 128
Other	39 124	38 853	31 952
	570 805	599 495	592 640
Onshore			
Contract	110 288	124 766	102 868
Multi-client pre-funding	12 761	16 443	14 104
Multi-client late sales	10 112	9 215	1 726
	133 161	150 424	118 698
Production			
Petrojarl I	61 303	69 615	62 631
Petrojarl Foinaven	96 595	112 099	133 364
Ramform Banff	51 509	45 188	37 886
Petrojarl Varg	87 133	67 795	69 455
Other	1 662	590	3 309
	298 202	295 287	306 645
Other/elimination	(56 834)	(32 612)	(7 449)
Total revenues (services)	945 334	1 012 594	1 010 534
Revenues (products) — Pertra	184 134	121 641	32 697
Total revenues	$ 1 129 468	$ 1 134 235	$ 1 043 231

(1) Combination of successor and predecessor.

Our revenues for 2004 decreased $4.8 million as compared with combined 2003 revenues for Predecessor and Successor. Pertra revenues increased by $62.5 million, but this increase was more than offset by a decrease of revenues in Marine Geophysical ($28.7 million) and Onshore ($17.3 million) and higher elimination of inter-segment revenues as described below.

Marine Geophysical

Marine Geophysical 2004 revenues decreased by $28.7 million (5%) as compared with 2003 (combined). Revenues from contract seismic acquisition decreased by $53.0 million (15%), primarily due to a close down of our ocean bottom 2C crew in late 2003. Revenues from this crew amounted to $40.5 million in 2003 (combined). In addition, contract revenues were negatively impacted by a weak contract market in the first half of 2004 and significant operating disturbances during completion of a large turnkey project offshore India in the second quarter. Revenues from multi-client late sales increased by $43.2 million (27%), reflecting overall high demand in the second half of 2004. In 2004, we reduced further our acquisition of multi-client data, and revenues from multi-client pre-funding decreased by $19.2 million (39%). Pre-funding as a percentage of cash investments in multi-client data increased to 99% in 2004 compared to 72% in 2003. In 2004, we allocated the active vessel time for our seismic fleet between contract and multi-client data acquisition approximately 89% and 11%, respectively, as compared to approximately 81% and 19%, respectively, in 2003.

Onshore

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

Production

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

Elimination of Inter-Segment Amounts.
In 2004, elimination of inter-segment revenues and costs (which reduces consolidated revenues and operating costs), increased by $23.9 million and $22.3 million, respectively, as compared to 2003 (combined) primarily due to increased payments from Pertra to Production for the use of *Petrojarl Varg*. Since August 2002, 70% of *Petrojarl Varg* revenues related to Pertra's interest in the Varg field have been eliminated in the consolidated financial statements. These inter-segment revenues aggregated $60.4 million, $45.1 million and $14.9 million in 2004, 2003 (combined) and 2002, respectively.

Pertra
Pertra revenues for 2004 increased $62.5 million (51%) as compared with 2003 (combined) primarily due to increased production of oil. Pertra's net oil production in 2004 was 5.3 million barrels compared to 4.1 million barrels in 2003 and 1.3 million barrels in 2002 (five months).

Cost of Sales

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

(In thousands of dollars, except percentage data)	Year Ended December 31, 2004	Year Ended December 31, 2003[2]	Year Ended December 31, 2002
Marine Geophysical	$ 342 460	$ 304 868	$ 286 324
% of revenue	60.0%	50.9%	48.3%
Onshore	$ 92 290	$ 89 677	$ 98 769
% of revenue	69.3%	59.6%	83.2%
Production	$ 167 764	$ 154 322	$ 144 261
% of revenue	56.3%	52.3%	47.0%
Other	$ 9 558	$ 7 676	$ 4 286
Transfer of cost[1]	(24 160)	(7 103)	(3 254)
Total cost of sales (services)	$ 587 912	$ 549 440	$ 530 386
% of revenue	62.2%	54.3%	52.5%
Cost of sales (products)			
Pertra	$ 93 035	$ 68 950	$ 27 430
Elimination[1]	(48 197)	(33 658)	(16 629)
Total cost of sales (products)	$ 44 838	$ 35 292	$ 10 801
% of revenue	24.3%	29.0%	33.0%
Total cost of sales	$ 632 750	$ 584 732	$ 541 187
% of revenue	56.0%	51.6%	51.9%

(1) Elimination of inter-segment charter hire related to Petrojarl Varg and inter-segment transfers of costs.
(2) Combination of successor and predecessor.

Cost of sales services
Cost of sales (services) increased by $38.5 million in 2004 as compared with 2003 (combined) primarily due to reduced multi-client activity in our Marine Geophysical business as we increased our focus in 2004 on contract marine seismic acquisition as compared to 2003. As a result, we reduced costs capitalized as investment in multi-client library by $49.5 million. In addition, cost of sales increased due to general cost increases driven by a weakening of the U.S. dollar against the British pound and the Norwegian kroner (which increases the reported U.S. dollar cost of expenses incurred in those currencies) and increased fuel prices, partially offset by the effect of closing down our ocean bottom 2C crew in late 2003. Production's cost of sales increased by $13.4 million, primarily due to increased materials purchases reimbursed by a customer, a weakening of the U.S. dollar exchange rate (which increases the reported U.S. dollar cost for Production since a significant part of these costs are incurred in British pounds and Norwegian kroner) and increased maintenance expense. Production's cost of sales includes all of the operating costs for *Petrojarl Varg* while 70% of these costs are eliminated from cost of sales (services) and included in cost of sales (products) and 70% of *Petrojarl Varg* revenues are eliminated from cost of sales (products) representing the 70% interest Pertra had in the Varg field.

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

Eliminations
Total elimination of inter-segment cost (which reduces consolidated operating costs) in 2004 increased by $22.3 million compared to 2003 (combined) primarily due to increased payments from Pertra to Production for the use of *Petrojarl Varg*.

Exploration Costs

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

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

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization ("DD&A") expenses result primarily from the allocation of capitalized costs over the estimated useful lives of our geophysical seismic 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, which we refer to as MCDL Amortization, and the amortization of certain intangible assets recognized upon our adoption of fresh start reporting effective as of November 1, 2003.

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

(In thousands of dollars)	Year Ended December 31, 2004	Year Ended December 31, 2003[(1)]	Year Ended December 31, 2002
Marine Geophysical:			
Adjusted DD&A	$ 55 277	$ 69 295	$ 64 616
MCDL amortization	186 435	161 271	183 317
DD&A	241 712	230 566	247 933
Onshore:			
Adjusted DD&A	18 677	17 863	17 077
MCDL amortization	21 208	17 786	11 331
DD&A	39 885	35 649	28 408
Production:			
DD&A	44 561	51 530	70 958
Pertra:			
DD&A	38 965	31 569	12 695
Corporate and other:			
Adjusted DD&A	2 414	5 272	6 203
MCDL amortization	825	2 689	1 306
DD&A	3 239	7 961	7 509
Total:			
Adjusted DD&A	159 894	175 529	171 549
MCDL amortization	208 468	181 746	195 954
DD&A	$ 368 362	$ 357 275	$ 367 503

(1) Combination of successor and predecessor.

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

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

Selling, General and Administrative Costs

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

Impairments and other operating (income) expense, net

Since we generally evaluate our multi-client library on a survey by survey basis at the end of each year, we expect to write down the value of some surveys each year due to survey specific factors. In 2004, we reported no impairments since we classified as amortization, rather than impairments, $19.9 million in write downs of individual surveys that related to individual survey-specific factors and that were not individually material.

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

We recorded other operating (income) expense, net, of $8.1 million in 2004, primarily relating to costs to complete the 2002 US GAAP consolidated financial statements and the re-audit of our US GAAP financial statements for the year ended December 31, 2001. In 2003 (combined) we recorded other operating (income) expense, net, of $22.4 million, primarily relating to severance payments that aggregated $19.8 million.

Interest expense and other financial items

Interest expense for 2004 totaled $110.8 million compared to $99.0 million for the first ten months (Predecessor) and $16.9 million for the last two months (Successor) of 2003. Our average interest bearing debt was significantly lower in 2004 compared to 2003, but in 2003 most of our debt did not accrue interest for approximately 100 days while we were in Chapter 11 proceedings.

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

Other financial items, net, amounted to an expense of $10.9 million in 2004 compared to an expense of $5.7 million in 2003 (combined). The increase in expense primarily relates to the cost to obtain from our bondholders waivers of certain requirements to report financial statements on a US GAAP basis.

Reorganization items

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

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

Income tax expense

Income tax expense was $48.0 million in 2004 compared with $18.1 million in 2003 (combined) excluding tax relating to discontinued operations and the adoption of fresh start reporting. Tax expense in 2004 included current taxes of $20.8 million and net deferred tax expense of $27.2 million. Taxes payable related primarily to foreign taxes in regions where we are subject to withholding taxes or deemed to have a permanent establishment and where we had no carryover losses. Current taxes included a $9.5 million charge related to tax contingencies. Deferred tax expense related primarily to Pertra where we make a full deduction of capital expenditures for tax purposes in the year these are incurred. Pertra is subject to petroleum taxation rules in Norway at a nominal tax rate of 78%, and Pertra cannot offset its income against losses from other operations. For information about how we evaluate the need for valuation allowances related to deferred tax assets, please read note 20 of the consolidated financial statements.

Discontinued Operations

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

Operating profit (loss) and net income (loss)

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

We reported a net loss of $134.7 million for 2004. For 2003 we reported net income of $557.0 million for the first ten months (Predecessor) and a net loss of $10.0 million for the last two months (Successor). As described above, net income for the first ten months of 2003 is significantly impacted by the effects of our financial reorganization, including gain on debt discharge of $1,253.9 million, adoption of fresh start reporting ($532.3 million), and impairment charges ($95.0 million).

Outlook

The markets in which we operate improved during 2004. Oil prices varied significantly through 2004, but generally at relatively high levels. We understand that market analysts generally expect high price levels for oil and natural gas to continue. In the medium to long-term, high oil price levels should positively impact our core markets.

Over the past few years, oil and natural gas exploration and production companies have made relatively low investments in exploration. We believe that as companies continue to focus on replacing oil and natural gas reserves in the coming years, such companies will be gradually more active in exploration.

We also believe that, after a number of years of overcapacity in the marine seismic market, the market has improved and industry order backlog and margins have increased. Within our Production segment, we believe that increased industry focus on smaller fields and tail-end field optimization forms a basis for growth in outsourcing where our Production segment is well positioned in the North Sea and has the potential to expand into selected international markets.

In 2005, after the sale of our oil and natural gas subsidiary Pertra, we operate from a more focused oil services base seeking to build our competitive advantage and market position. At the same time, we intend to continue to manage our business in a financially disciplined manner, focusing on improvement in return on capital employed, cash generation and prudent risk management.

In 2005, we expect the following factors to influence our performance:

Marine Geophysical

- Increased contract prices driven by relatively high industry capacity utilization;
- Continued focus on contract acquisition, with a moderate increase in multi-client activity;
- Lower multi-client late sales as compared with 2004 due to limited reinvestment over the past three years and expected delay of Brazilian 7th Licensing Round sales into 2006; and
- Increased costs due to increased fuel prices and a weaker U.S. dollar compared to 2004.

Onshore

- Continued focus on markets where we can compete most effectively; and
- Full year activity level similar to that in 2004, building on expected start-up of a significant transition zone project in Nigeria and contract awards for crews in South America.

Production

- Continued production by our FPSOs on existing assignments;
- Total oil production from the four FPSOs in line with 2004 levels; and
- Increased operating costs due to (a) increased maintenance costs on FPSO vessels as the time since deployment of the FPSOs on their respective fields is increasing and (b) a weakened U.S. dollar as compared to 2004.

Liquidity and Capital Resources

Liquidity — General

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 2005 and 2006. While we believe that we have adequate sources of funds to meet our liquidity needs for the 2005-2006 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.

While we have made some progress since we completed our financial restructuring in late 2003 in strengthening our balance sheet and increasing our financial flexibility, we remain committed to strengthen further our financial flexibility. As a result, we intend to use our available cash flow to develop our core businesses and to maintain or improve financial ratios.

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 $132.9 million at December 31, 2004, an increase from $105.2 million at December 31, 2003. In addition, in March 2005 we sold our oil and natural gas subsidiary Pertra and thereby realized a net cash proceeds of approximately $150 million. In April 2005, we redeemed $175 million of our 8% Senior Notes due 2006.

Net cash provided by operating activities totaled $282.4 million in 2004, representing an increase of $55.3 million compared with 2003 (combined). In 2004, our restructuring costs were significantly less than in 2003. In 2004, our accounts receivables, net, increased $33.6 million, but the cash flow effect was offset by a $25.6 million increase in accounts payable and a $15.6 net release of restricted cash.

Our external sources of liquidity include our secured revolving credit facility, equipment financing and trade credit. Subject to market conditions and other factors, we might also seek to raise debt or equity in the capital markets.

We have 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 assets. Borrowings under the facility bear interest at LIBOR plus 2%. At December 31, 2004, approximately $15 million of letters of credit were outstanding under this facility. No borrowings were outstanding under the revolving credit portion of the facility at December 31, 2004. We will seek to establish a similar facility when this one matures in March 2006.

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

The book value of our debt, including capital leases, was approximately $1,164 million as of December 31, 2004 compared to approximately $1,211 million at December 31, 2003.

Our debt consisted of the following primary components at December 31, 2004 (in millions):

10% Senior Notes, due 2010	$ 746
8% Senior Notes, due 2006	250
8.28% First Preferred Mortgage Notes, due 2011	99
Other loans, due 2005 — 2006	10
Total debt	$ 1 105
Capital leases	59
Total	$ 1 164

Net interest bearing debt (interest bearing debt, including capital leases, less cash and cash equivalents and restricted cash) was approximately $995 million as of December 31, 2004 compared to $1,077 million (adjusted for the final excess cash distribution of $22.7 million that was included in accrued expenses) at December 31, 2003.

In April 2005, we redeemed $175 million of our $250 million 8% Senior Notes due 2006 at a redemption price of 102% of the principal amount of the notes redeemed. The remaining balance of the 8% notes may be redeemed at a redemption price of 101% of the outstanding principal amount starting in November 2005.

Certain of our loan and lease agreements and our senior note indenture require us 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. We have received waivers from the various lenders allowing us to report under those agreements and the indenture under Norwegian GAAP in lieu of US GAAP until June 30, 2005.

In addition to customary representations and warranties, certain of our debt agreements restrict us from incurring debt unless specified coverage ratios are met and limit 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.

Net Cash Used in Investing and Financing Activities

Net cash used in investing activities totaled $183.4 million in 2004, an increase of $88.6 million compared with 2003 (combined). This increase was primarily due to (a) a $90.3 million increase in capital expenditures, and (b) a $48.1 million reduction in cash inflow from the sale of subsidiaries, offset in part by (c) a $49.5 million reduction in cash investment in multi-client library reflecting our continued focus on the contract market. Our capital expenditures increased primarily due to (x) increased capital expenditures in our oil and natural gas subsidiary, Pertra, relating to an extensive drilling program, (y) increased capital expenditures on the streamer replacement program in Marine Geophysical, and (z) increased investments in data processing equipment and normal equipment replacement after unusually low levels during 2003, the year of our financial restructuring.

Net cash used in financing activities totaled $71.3 million in 2004, representing a decrease of $47.4 million compared to 2003. In 2004, we made net repayments of long-term debt and principal payments under capital leases totaling $47.1 million, a reduction of $53.6 million compared to 2003. We also made in 2004 a $22.7 million distribution of excess cash to creditors under the debt restructuring agreement compared to a similar distribution of $17.9 million in 2003.

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 ongoing capital requirements, other than debt service, lease obligations and contingencies, consists of:

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

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

In prior years, our capital expenditures have related not only to normal ongoing equipment replacement and refurbishment needs, but also to increases in our seismic data acquisition capacity and in our FPSO operations. Such expenditures, which can be substantial from time to time, depend to a large extent upon the nature and extent of future commitments that are largely discretionary. In 2004, 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 2004 (in millions):

Segment	Amount
Marine Geophysical	$ 56.9
Onshore	1.4
Production	1.0
Pertra	85.0
Other	4.1
Total	$ 148.4

For 2005, we expect:

- to prudently increase our investment in multi-client library as compared to 2004 as we start rebuilding our multi-client business;
- capital expenditures in Marine Geophysical to be largely in line with 2004 as we continue our streamer replacement program and otherwise continue to invest in upgrading our seismic vessels and data processing equipment;
- capital expenditures in Onshore to increase to above $10 million as we expect to make investments in specialized equipment within certain areas, including transition zone recording equipment; and
- capital expenditures in Production on our existing vessels to continue at a low level because our FPSO vessels are not expected to have substantial replacement needs through 2005 and we expense maintenance expenditures.

As of March 31, 2005, 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.

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 also intend to make maintenance and refurbishment expenditures as required so as to maintain our fleet of marine seismic and FPSO vessels in good working order. We intend to make other capital expenditures in our business segments as conditions dictate and financial resources permit. Finally, we may also incur capital expenditures significantly above the amounts described above to pursue new business opportunities for any of our business segments.

Long-Term Contractual Obligations

The following table presents our long-term contractual obligations related to our loan and lease agreements and other long-term liabilities and related payments due in total and by period as of December 31, 2004:

		Payments Due by Period			
(In millions of dollars)	Total	2005	2006 - 2007	2008 - 2009	Thereafter
Contractual Obligations					
Long term debt obligations	$ 1 103.0	$ 17.8	$ 276.1[1]	$ 29.2	$ 779.8
Operating lease obligations	163.6	36.4	45.4	43.9	37.8
Capital lease obligations	62.1	27.4	28.1	6.6	—
Other long-term liabilities[2]	158.2	16.2	33.7	76.7	31.6
Totals	$ 1 486.9	$ 97.8	$ 383.3	$ 156.4	$ 849.2

(1) This amount includes the maturity of $250 million of our 8% Senior Notes due 2006. We redeemed $175 million of these notes in April 2005.
(2) Excluding other long-term liabilities that are contingent or that have uncertain future cash flows.

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.

The table below is provided to illustrate the expected timing of future payments related to other long-term liabilities reported in our consolidated balance sheet as of December 31, 2004. Determining the expected future cash flows presented in the table requires us to make estimates and assumptions since the timing of any payments related to these long-term liabilities generally is not fixed and determinable but rather depends on future events. We believe that our estimates and assumptions are reasonable, but actual results may vary from what we have estimated or assumed. As a result, our reported liabilities and expenses could be materially affected if the assumptions and estimates we have made were changed significantly.

		Payments Due by Period				
(In millions of dollars)	Total	2005	2006 - 2007	2008 - 2009	Thereafter	Not determinable
Contractual Obligations						
Pension liability[1]	$ 52.5	$ 7.9	$ 16.2	$ 17.0	$ 11.4	$ —
Asset removal obligations[2]	58.5	0.3	—	39.9	18.3	—
Accrued liabilities related to our UK leases:						
— related to interest rate differential[3]	47.2	8.0	17.5	19.8	1.9	—
— related to tax indemnifications	32.1	—	—	—	—	32.1
Tax contingencies	25.5	—	—	—	—	25.5
Other	3.8	—	—	—	—	3.8
Totals	$ 219.6	$ 16.2	$ 33.7	$ 76.7	$ 31.6	$ 61.4

(1) Pension liability represents the aggregate shortfall of pension plan assets compared to projected benefit obligations for our plans. We will pay this obligation over time, as adjusted for changes in estimates relating to obligations and assets, in accordance with the funding requirements of the life insurance companies through which we fund our plans. Such requirements are subject to change over time, but we expect these payments to be made over several years. We have used the premiums expected to be paid in future periods as an estimate of future cash outflows related to this liability. These premiums would generally relate both to payments of the pension obligations as of December 31, 2004 and service cost for future years.
(2) Asset removal obligations as of December 31, 2004 include $39.9 million relating to our Pertra oil and natural gas subsidiary that is included in amounts expected to be due for payments in the period 2008 — 2009. We sold Pertra in March 2005 to Talisman, and the buyer assumed this obligation as part of the transaction.
(3) The estimated net present value of future payments related to interest rate differential on our UK leases as of December 31, 2004 is $56.9 million based on forward interest rate curves, which is $9.7 million higher than the amount included in accrued liabilities. Payments through the year 2009 reflect estimated total payment based on forward interest rate curves as of December 31, 2004. The amount presented for periods after 2009 is the residual amount.

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 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 and interpretations of UK tax laws 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 2004, 2003 and 2002, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $6.3 million, $6.4 million and $3.9 million, respectively, for those years.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. We understand that the UK Inland Revenue has generally deferred agreeing to the capital allowances claimed under such leases pending the outcome of a case that was appealed to the UK House of Lords, the highest UK court of appeal. In that case, the Inland Revenue was challenging capital allowances associated with a defeased lease. In November 2004, the House of Lords ruled in favor of the taxpayer and rejected the position of the UK Inland Revenue. We have been informed that in 2005, the Inland Revenue has accepted the lessor's claims to capital allowances for three of our UK leases. As a result of the November 2004 decision by the UK House of Lords, we believe it is unlikely that our UK leases will be successfully challenged by the Inland Revenue. Nevertheless, in connection with our adoption of fresh start reporting and before the House of Lords ruling, we recorded a liability of $28.3 million as of October 31, 2003 for this specific contingency in accordance with the requirements of SOP 90-7. At December 31, 2004 and 2003, this liability amounted to $32.1 million and $29.5 million, respectively. We expect to release appropriate portions of this liability if and when the UK Inland Revenue accepts the lessor's claims for capital allowances under each lease.

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).

For additional information regarding our UK leases, please see notes 2 and 19 of the notes to our consolidated financial statements.

Research and Development

We incurred research and development costs of $3.4 million, $2.6 million and $2.8 million during the years ended December 31, 2004, 2003 and 2002, respectively.

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, 2004, we had one open interest rate swap with the notional amount of $10.3 million and no interest rate lock agreements. 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, 2004:

(Dollar amounts in thousands)	2005	2006	2007	2008	2009	Thereafter
Debt:						
Fixed Rate	$ 10 990	$ 261 920(1)	$ 12 900	$ 14 040	$ 15 160	$ 779 860
Average Interest Rate	8.28%	8.01%	8.28%	8.28%	8.28%	9.93%
Variable Rate	$ 8 799	$ 1 312	—	—	—	—
Average Interest Rate	4.47%	4.22%	—	—	—	—

(1) The amount includes our $250 million 8% Senior Notes due 2006. We redeemed $175 million of these notes on April 7, 2005.

As of December 31, 2004, we had capital lease obligations of $62.1 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 $0.6 million per year.

We have entered into certain capital leases in the United Kingdom. The leases are legally defeased because we have made payments to independent third-party banks in consideration for which these banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, we receive rental rebates. If, on the other hand, actual interest rates are less than the assumed interest rates, we are required to pay rentals in excess of the defeased rental payments. As of December 31, 2004, our balance sheet reflected a liability of $47.3 million for this interest rate exposure. This liability was recorded upon our adoption of fresh start reporting in November 2003 and is amortized based on rental payments after such adoption. During 2004, 2003 and 2002, actual interest rates were below the assumed interest rates, and we made additional required rental payments of approximately $6.3 million, $6.4 million and $3.9 million in the years 2004, 2003 and 2002, respectively. The estimated net present value of future payments related to interest differential on our UK leases as of December 31, 2004 is $56.9 million based on forward interest rate curves. For additional information with respect to our UK leases, please read notes 2 and 19 of the notes to our consolidated financial statements.

Foreign Currency Exchange Rate Risk

We conduct business in various currencies including the Brazilian real, Mexican peso, Bolivian boliviano, Dubi dirham, Bangladesh taka, Kazakhstan tenge, Indian rupee, Saudi Arabian riyal, British pound, the Norwegian kroner, the Egyptian pound, the Singaporian dollar and the Australian dollar. We are subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions in currencies other than the U.S. dollar. As of December 31, 2004 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 2004 was 5,317,134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2003 and 2004, we did not have any outstanding 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. Of the total amount sold forward, 250,000 barrels sold forward at an average price of $29.91 per barrel remained undelivered at December 31, 2004 and were delivered in early January 2005.

Internal Control Matters

In September 2003 our independent registered public accounting firm, Ernst & Young AS ("EY"), communicated to management and our Audit Committee material weaknesses regarding various elements of our system of internal controls over financial reporting. A material weakness is a significant control deficiency, or a combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

At the time of receiving the September 2003 communication from our independent registered public accounting firm, we were in the process of re-auditing our 2001 US GAAP financial statements and finalizing the audit of our US GAAP financial statements for 2002. As a result of the material weaknesses and other factors, including our 2003 financial reorganization and Chapter 11 proceeding, we were unable to prepare audited consolidated financial statements under US GAAP for 2001, 2002 and 2003 until November 2004. Further, in connection with the re-audit for 2001 and the audit of our financial statements for 2002 and 2003, we identified various accounting errors requiring restatement of our historical US GAAP financial statements for 2001.

Acting under the supervision and guidance of our Audit Committee and Board of Directors, our management has worked, with assistance from various consultants and contractors, to address these material weaknesses, including implementing our Sarbanes-Oxley Section 404 readiness project. We have made and continue to make significant changes to improve our internal control over financial reporting and to eliminate material weaknesses.

We believe that the actions taken to date have significantly improved our internal controls. We believe that these and the additional improvements identified and in progress will remediate the weaknesses. However, our assessment of the progress made in addressing the material weaknesses identified in September 2003 indicates that for the period relevant for the preparation of our 2004 financial statements and at December 31, 2004, certain matters, which we believe in aggregate constitute material weaknesses continued to exist.

In connection with the audit of our 2004 financial statements under US GAAP, our independent registered public accounting firm delivered to us a letter dated May 3, 2005 that also confirmed the continuation of these matters that, in the aggregate, they considered to constitute material weaknesses.

Our management, with the oversight of our Audit Committee and Board of Directors, is committed to the remediation of remaining control deficiencies in our internal control over financial reporting as expeditiously as possible. We believe that the actions that we have already taken will continue to improve our internal controls over financial reporting since many of these controls and remedial actions relate to people and processes that require time before they are fully effective. We will continue to implement our planned actions to fully remediate remaining weaknesses.

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

Petroleum Geo-Services

Consolidated Statements of Operations

(In thousands of dollars, except share data)	Successor Company: Year Ended December 31, 2004	Successor Company: Two Months Ended December 31, 2003	Predecessor Company: Ten Months Ended October 31, 2003	Predecessor Company: Year Ended December 31, 2002
Revenues services	$ 945 334	$ 162 827	$ 849 767	$ 1 010 534
Revenues products	184 134	9 544	112 097	32 697
Total revenues	1 129 468	172 371	961 864	1 043 231
Cost of sales services	587 912	95 044	454 396	530 386
Cost of sales products	44 838	1 910	33 382	10 801
Exploration costs	16 326	—	—	—
Depreciation and amortization	368 362	55 699	301 576	367 503
Research and development costs	3 419	598	2 024	2 766
Selling, general and administrative costs	64 816	7 366	44 326	53 426
Impairment of long-lived assets	—	—	95 011	558 471
Other operating (income) expense, net	8 112	1 052	21 324	8 487
Total operating expenses	1 093 785	161 669	952 039	1 531 840
Operating profit (loss)	35 683	10 702	9 825	(488 609)
Financial items:				
Income (loss) from associated companies	668	200	774	(11 501)
Interest expense	(110 811)	(16 870)	(98 957)	(153 301)
Other financial items, net	(10 861)	(4 264)	(1 472)	33 792
	(85 321)	(10 232)	(89 830)	(619 619)
Reorganization items:				
Gain on debt discharge	—	—	1 253 851	—
Fresh-start adoption	—	—	(532 268)	—
Cost of reorganization	(3 498)	(3 325)	(52 334)	(3 616)
Minority expense	940	110	570	778
Income tax expense (benefit)	48 019	(3 849)	21 911	185 890
Income (loss) from continuing operations before cumulative effect of change in accounting principles	(137 778)	(9 818)	556 938	(809 903)
Income (loss) from discontinued operations, net of tax	3 048	(135)	(2 282)	(201 137)
Income (loss) before cumulative effect of change in accounting principles	(134 730)	(9 953)	554 656	(1 011 040)
Cumulative effect of change in accounting principles, net of tax	—	—	2 389	(163 638)
Net income (loss)	$ (134 730)	$ (9 953)	$ 557 045	$ (1 174 678)
Basic and diluted income (loss) per share from continuing operations	$ (6.89)	$ (0.49)	$ 5.39	$ (7.84)
Income (loss) from discontinued operations, net of tax	0.15	(0.01)	(0.02)	(1.95)
Cumulative effect of change in accounting principle, net of tax	—	—	0.02	(1.58)
Basic and diluted net income (loss) per share	$ (6.74)	$ (0.50)	$ 5.39	$ (11.37)
Weighted average basic and diluted shares outstanding	20 000 000	20 000 000	103 345 987	103 345 987

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

Petroleum Geo-Services

Consolidated Balance Sheets

(In thousands of dollars)	December 31, 2004	2003
ASSETS		
Cash and cash equivalents	$ 132 942	$ 105 225
Restricted cash	25 477	41 123
Shares available for sale	9 689	—
Accounts receivable, net	161 283	127 706
Unbilled and other receivables	40 561	47 864
Other current assets	60 506	62 610
Total current assets	430 458	384 528
Multi-client library, net	244 689	408 005
Property and equipment, net	1 009 008	1 060 183
Oil and natural gas assets, net	71 491	36 426
Restricted cash	10 014	10 014
Investments in associated companies	5 720	8 070
Intangible assets, net	36 114	52 609
Other long-lived assets	44 659	37 525
Total assets	$1 852 153	$1 997 360
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt and current portion of long-term debt	$ 19 790	$ 18 512
Current portion of capital lease obligations	25 583	19 963
Accounts payable	81 910	56 318
Accrued expenses	115 256	147 336
Deferred tax liabilities	761	2 166
Income taxes payable	11 870	17 946
Total current liabilities	255 170	262 241
Long-term debt	1 085 190	1 108 674
Long-term capital lease obligations	33 156	63 473
Other long-term liabilities	219 650	197 663
Deferred tax liabilities	35 118	10 738
Total liabilities	1 628 284	1 642 789
Minority interest in consolidated subsidiaries	962	937
Shareholders' equity:		
Common stock; 20 000 000 shares authorized, issued and outstanding, par value NOK 30, at December 31, 2004 and 2003	85 714	85 714
Additional paid-in capital	277 427	277 427
Accumulated deficit	(144 683)	(9 953)
Accumulated other comprehensive income	4 449	446
Total shareholders' equity	222 907	353 634
Total liabilities and shareholders' equity	$1 852 153	$1 997 360

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

Petroleum Geo-Services

Consolidated Statements of Cash Flows

(In thousands of dollars)	Successor Company Year Ended December 31, 2004	Successor Company Two Months Ended December 31, 2003	Predecessor Company Ten Months Ended October 31, 2003	Predecessor Company Year Ended December 31, 2002
Cash flows (used in) provided by operating activities:				
Net income (loss)	$(134 730)	$ (9 953)	$ 557 045	$ (1 174 678)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization charged to expense	368 362	55 699	301 576	367 503
Exploration costs (dry well expensed)	11 438	—	—	—
Non-cash impairments, loss (gain) on sale of subsidiaries and change in accounting principles, net	—	32	92 622	935 244
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
Provision for deferred income taxes	27 263	(5 801)	(1 918)	171 771
(Increase) decrease in accounts receivable, net	(33 577)	34 582	6 848	(22 628)
Increase (decrease) in accounts payable	25 592	19 391	(18 587)	(10 814)
Loss on sale of assets	4 128	—	6 193	11 750
Net (increase) decrease in restricted cash	15 646	3 824	(23 728)	1 602
Other items	(1 750)	(35 761)	(51 674)	9 319
Net cash provided by operating activities	282 372	62 170	164 948	294 609
Cash flows (used in) provided by investing activities:				
Investment in multi-client library	(41 140)	(9 461)	(81 142)	(151 590)
Capital expenditures	(148 372)	(15 985)	(42 065)	(56 735)
Capital expenditures on discontinued operations	—	—	(118)	(77 364)
Sale of subsidiaries	2 035	—	50 115	20 222
Other items, net	4 031	357	3 478	(9 030)
Net cash used in investing activities	(183 446)	(25 089)	(69 732)	(274 497)
Cash flows (used in) provided by financing activities:				
Repayment of long-term debt	(24 167)	(4 850)	(70 496)	(340 809)
Principal payments under capital leases	(22 930)	(3 025)	(22 352)	(19 839)
Net increase (decrease) in bank facility and short-term debt	1 962	—	(48)	335 348
Net receipts under tax equalization swap contracts	—	—	—	9 566
Distribution to creditors under the restructuring agreement	(22 660)	(17 932)	—	—
Other items, net	(3 488)	—	—	8 098
Net cash used in financing activities	(71 283)	(25 807)	(92 896)	(7 636)
Effect of exchange rate changes on cash	74	—	14	537
Net increase in cash and cash equivalents	27 717	11 274	2 334	13 013
Cash and cash equivalents at beginning of period	105 225	93 951	91 617	78 604
Cash and cash equivalents at end of period	$ 132 942	$105 225	$ 93 951	$ 91 617

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

Supplementary cash flow information is included in note 27.

Petroleum Geo-Services

Notes to the Consolidated Financial Statement

Note 1 General Information about the Company and Basis of Presentation

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

PGS is a technologically focused oilfield service company principally involved in providing geophysical services worldwide and floating production services in the North Sea. Globally, 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. Through 2004, the Company also owned a small oil and natural gas company that produces oil and natural gas from a license on the Norwegian Continental Shelf. The Company sold this oil and natural gas subsidiary in March 2005. The Company's headquarters are at Lysaker, Norway. See further discussion of the Company's services in Note 26.

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

As more fully described in Note 23, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. in December 2003. The Company sold its Production Services subsidiary in December 2002 and its Atlantis subsidiary in February 2003. Accordingly, the financial position and results of operations and cash flows for these subsidiaries have been presented as discontinued operations as of December 31, 2003 and 2002 and for the years then ended. The results of operations and cash flows for the year ended December 31, 2004 includes contingent proceeds from discontinued operations sold in 2002.

The accompanying financial statements have been prepared on the basis of accounting principles that assume the realization of assets and the settlement of liabilities in the ordinary course of business. Accordingly, the financial statements do not purport to present the realizable values of all assets or the settlement amounts of all liabilities, and therefore, do not reflect any adjustments in the carrying values of our assets, liabilities, income statement items and balance sheet classifications that would be necessary if our financial statements were not prepared on a going concern basis.

In 2003 the Company, as more fully described in Note 15, successfully completed a financial restructuring that involved cancellation of all pre-restructuring share capital and a reduction of interest bearing debt of $1,283 million from $2,472 million to $1,189 million. Costs relating to this restructuring totalled $3.5 million for the year ended December 31, 2004, $3.3 million for the two months ended December 31, 2003 and $52.3 million for the ten months ended October 31, 2003 (including $13.2 million in write-off of deferred debt costs and issue discounts).

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

Note 2 Summary of Significant Accounting Policies

Fresh Start Reporting.

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

- The successful efforts method of accounting for oil and natural gas exploration and development activities was adopted.
- The Company made certain changes to cost capitalization and amortization policies for the multi-client library, including an increase in minimum amortization by reducing the maximum amortization period from eight to five years after completion of a survey. Further, expenditures incurred in connection with yard stay and steaming of vessels are expensed as incurred. Such expenses were previously recognized as part of multi-client project costs.

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

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

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

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

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

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

The Company has concluded that it is the primary beneficiary of two VIEs, DMNG PGS AS and Walter Herwig AS. Accordingly, these entities are consolidated in the Successor's financial statements. By December 31, 2003 Walter Herwig AS had become 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 (see Note 19) in relation to FIN 46R. As part of the evaluation process, the Company has requested further information about the lessor entities, including information related to their other assets and contractual arrangements. However, the Company has no rights under its agreements with the lessor entities to request or receive such information, and the lessor entities (or their owners) have denied the Company access to any such information. Accordingly, the Company has not been able to affirmatively determine if any of the lessor entities are VIEs, and if any are VIEs, who the primary beneficiary would be.

However, based on information received from the lessor entities, which all have multiple lessees, 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).

Discontinued Operations.

Subsidiaries that are either held-for-sale or discontinued are reported as discontinued operations. Revenues and expenses are excluded from revenue and expenses of the Company and reported separately as a one line item in the consolidated statement of operations, net of tax. Assets and liabilities are presented as separate line items in the balance sheet. For further details about subsidiaries that we have sold or operations that we have discontinued, see Note 23.

Cash and Cash Equivalents.

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

Cash and cash equivalents that are restricted from the Company's use are disclosed separately in the consolidated balance sheets and are classified as current or long-term depending on the nature of the restrictions. Such restrictions primarily relate to cash collateral for bid or performance bonds, employee tax withholdings, restricted deposits under contracts, and cash in our wholly owned captive insurance company. Restricted cash related to bid or performance bonds amounted to $11.7 million at December 31, 2004 and $27.3 million at December 31, 2003.

Foreign Currency Translation.

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

The financial statements of non-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 Company's exchange rate between the Norwegian kroner and U.S. dollar at December 31, 2004 and 2003 was NOK 6.13 and 6.79, respectively.

Operating and Capital Leases.

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

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

UK Leases.

The Company has entered into vessel lease arrangements in the United Kingdom ("UK leases") relating to five of our Ramform design seismic vessels, our FPSO vessel *Petrojarl Foinaven* and the topsides of our FPSO vessel *Ramform Banff* (Note 19). 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. The Lessors claims tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. 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 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"). Such payments are made annually or bi-annually and are recorded on a straight line basis as other financial items, net.

Effective November 1, 2003, the Company adopted fresh start reporting and recorded a liability equal to the fair value of the future Additional Required Rental Payments. Such fair value was estimated at the net present value of the Additional Required Rental Payments based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, and was amortized to 27.4 million British pounds ($48.6 million) at December 31, 2003. At December 31, 2004, the liability was amortized to 24.6 million British pounds (approximately $47.2 million).

For fresh start reporting purposes, the Company 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 recorded a 16.7 million British pounds ($28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. At December 31, 2004 and 2003 this liability amounted to $32.1 million and $29.5 million, respectively.

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, the Company no longer capitalizes such indirect costs.

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

Amortization of the multi-client library is generally recorded in proportion to revenue recognized to date as a percentage of the total expected revenue. In determining the annual amortization rates applied to the multi-client library, management considers expected future sales and market developments and past experience. These expectations include consideration of geographic location, prospects, political risk, exploration license periods and general economic conditions. The local sales and operating management update, 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 estimates. Each category therefore includes surveys as to which the remaining book value as a percentage of remaining estimated sales is less than or equal to the amortization rate applicable to that category.

An integral component of amortization of the multi-client library is the minimum amortization policy. Under this policy, the book value of each survey or group of surveys of the multi-client library is reduced to a specified percentage by year-end, based on the age of each survey or group of surveys in relation to their year of completion. This requirement is applied each year-end regardless of future revenue estimates for the multi-client library survey or group of surveys. The specified percentage generates the maximum 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

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

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

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 not to have commercial quantities of reserves, the drilling and equipment costs for the well are expensed and classified as exploration costs at that time. Such expenses aggregated $11.4 million for the year ended December 31, 2004. All development drilling and equipment costs are capitalized. Capitalized costs of proved properties are amortized on a property-by-property basis using the unit-of-production method whereby the ratio of annual production to beginning of period proved oil and natural gas reserves is applied to the remaining net book value of such properties. Oil and natural gas reserve quantities represent estimates only and there are numerous uncertainties inherent in the estimation process. Actual future production may be materially different from amounts estimated, and such differences could materially affect future amortization of proved properties. Geological and geophysical costs are expensed as incurred and presented as exploration costs. Such costs aggregated $8.6 million for the year ended December 31, 2004.

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.

Following its adoption of fresh start reporting, the Company has no goodwill balances.

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 be 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 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 is 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 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 4).

Intangible Assets.

Intangible assets relate to direct costs of software product for internal use, patents, royalties and licenses. Substantially all of the Company's intangible assets were recognized as a consequence of the Company's adoption of fresh start reporting. Such intangible assets include 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 costs related to entering into long-term loan facilities (deferred debt issue costs) and long-term receivables. The Company capitalizes debt issue costs relating to long-term debt, and such costs are charged to interest expense using the effective interest method over the period the associated debt is outstanding. Other long-term receivable includes accounts receivable expected to be collected more than twelve months after the balance sheet date including government grants and contractual receivables related to asset removal obligations.

Impairment of Long-Lived Assets.

Long-lived assets, which consist primarily of multi-client library, property, plant and equipment and oil and gas assets (or the group of assets, including the asset in question, that represents the lowest level of separately identifiable cash flows), are assessed for possible impairment when indications of impairments exist in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). 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 also assessed for possible impairment upon the occurrence of a triggering event. Events that can trigger assessments for possible impairments include, but are not limited to (i) significant decreases in the market value of an asset, (ii) significant changes in the extent or manner of use of an asset, (iii) a physical change in the asset, (iv) a reduction of proved oil and natural gas reserves based on field performance and (v) a significant decrease in the price of oil or natural gas.

Steaming and Mobilization.

Subsequent to the adoption of fresh start reporting, costs incurred while 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 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.

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 as other financial items, net 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 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, 2004 and 2003, the Company did not have outstanding any derivative financial instruments that qualified for hedge accounting.

The Company operates 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 (see Note 18).

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". No compensation cost is recognized under the Company's plans since the option exercise price is above or equal to market value of the stock at the 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.

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. For contracts after July 1, 2003, the provisions of EITF 00-21, "Revenue Arrangement with Multiple Deliverables" apply. As a result, consideration is allocated among the separate units of accounting based on their relative fair values. The Company's revenue recognition policy is described in more detail below.

Revenue Services.

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

(a) Sales of Multi-Client Library Data.

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

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

Revenue recognition for volume sales agreements is based on a 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 Services.

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

Revenue Products (Pertra).

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

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

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

Income Taxes.

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

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

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 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 asset retirement obligation may result from changes in the assumptions used to estimate the cash flows required to settle the asset retirement obligation. The effect of such changes is recorded as an adjustment to the related asset. 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 covered in part by grants from the Norwegian government and in part with contractual payments from FPSO contract counterparties (see Note 11). 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, the impact on income before cumulative effect of changes in accounting principles and earnings per share would have been immaterial. 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 as of January 1, 2003.

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.

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.

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 the year ended December 31, 2002 are shown in the table below:

(In thousands of dollars, except per share data)	Loss from Continuing Operations Before Cumulative Effect of Change in Accounting Principle	Loss Before Cumulative Effect of Change in Accounting Principle	Net loss
Reported income (loss)	$ (809 903)	$ (1 011 040)	$ (1 174 678)
Asset removal obligation pro forma effect	362	362	362
Reverse cumulative effect of change in accounting principle	—	—	163 638
Pro forma income (loss)	$ (809 541)	$ (1 010 678)	$ (1 010 678)
Pro forma income (loss) per share (basic and diluted)	$ (7.83)	$ (9.78)	$ (9.78)

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. As a result, on July 29, 2003, the Company filed a voluntary petition for protection under Chapter 11 of the United States Bankruptcy Code. The filing was based on a financial restructuring plan that was pre-approved by a majority of banks and bondholders and a group of the Company's largest shareholders. The Company emerged from Chapter 11 on November 5, 2003.

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

Financial Restructuring.

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

- $746 million of unsecured 10% Senior Notes due 2010;
- $250 million of unsecured 8% Senior Notes due 2006;
- $4.8 million of an eight-year unsecured senior term loan facility (which the Company fully repaid in May 2004);
- 91% of new ordinary shares of PGS as constituted immediately post restructuring, with an immediate reduction of this shareholding to 61% through a rights offering of 30% of the new ordinary shares to the pre-restructuring shareholders for $85 million, or $14.17 per share; and
- $40.6 million 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, was cancelled and 20,000,000 new ordinary shares, par value NOK 30, were issued. The pre-restructuring shareholders received 4%, or 800,000, of the new ordinary shares (one new share per 129 old shares), and the right to acquire 30%, or 6,000,000, of the new ordinary shares (1,500,000 of which were committed to shareholders underwriting the rights offering and 4,500,000 of which were available to all pre-restructuring shareholders on a basis of one new share per 23 old shares), for $85 million ($14.17 per share) in the rights offering.

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

Reorganization Value.

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

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

Fresh Start Reporting.

The consolidated balance sheets as of December 31, 2004 and 2003 and the consolidated statements of operations and cash flows for the year ending December 31, 2004 and the two months ended December 31, 2003 are for the Successor and give effect to adjustments to the carrying value of assets or amounts and classifications of liabilities that were necessary upon adoption of fresh start reporting as of November 1, 2003. The consolidated statements of operations and cash flows for the year ended December 31, 2002 and for the ten months ended October 31, 2003 are for the Predecessor and reflect the assets and liabilities of PGS on a historical cost basis including the effect at October 31, 2003 of the fresh start adjustments. The adoption of fresh start reporting had a material effect on the consolidated balance sheets as of December 31, 2004 and 2003 and on the consolidated statements of operations for the year ending December 31, 2004 and the two-month period ending December 31, 2003 and will have a material impact on consolidated statements of operations for subsequent periods. Consequently, the financial information for the Successor and Predecessor companies are not comparable.

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

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

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

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

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

- The reorganization value of the Company was allocated to the Company's assets in conformity with the procedures specified by Statement of Financial Accounting Standards No. 141, "Business Combinations." The sum of the amounts assigned to assets and liabilities was within the range of the estimated reorganization value and close to the mid-range of the valuation. Therefore, there was no excess or deficit value to be allocated to goodwill or long-term assets.
- Each liability and contingency existing as of the fresh start reporting date, other than deferred taxes, has been stated at the present value of the amounts to be paid, determined at appropriate then current interest rates.
- Deferred taxes were recorded in conformity with applicable income tax accounting standards, principally Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes". Deferred tax assets and liabilities have been recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities (see Note 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 (prior to fresh start adjustments), 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		
(In thousands of dollars)	Predecessor Company	Effects of Plan	Fresh Start Valuation	Successor Company
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 Impairment of Long-Lived Assets and Other Operating Expense, Net

Impairments of long-lived assets consist of the following:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Multi-client library	$ —	$ —	$ 90 053	$ 200 393
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

During 2002 and 2003, the Company's sales estimates for several of its multi-client surveys were revised downward significantly, resulting in impairments of such surveys in 2002 and 2003. In 2002 the Company recorded an impairment charge of $332.0 million relating to the *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.

Other operating expense, net consists of the following:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Termination of employees and reorganization	$ 665	$ 582	$ 19 235	$ 9 570
Cost relating to completion of 2002 US GAAP accounts and re-audit 2001	7 447	470	2 089	—
Net gain related to canceled merger with Veritas DGC Inc	—	—	—	(2 864)
Other	—	—	—	1 781
Total	$ 8 112	$ 1 052	$ 21 324	$ 8 487

Note 5 Shares Available for Sale

Shares available for sale relates to the Company's investment in Endeavour International Corp. originally acquired through contribution of licenses to use PGS seismic data in the North Sea. The Company owns approximately 3.3% of Endeavour's shares, which had an original cost of $3.8 million. Under the terms of an agreement with Endeavour, the Company may not sell any of its shares for the first twelve months from the conversion date (February 2004); from twelve to twenty-four months, the Company may sell up to one-third of the equity per quarter. In adjusting the shares to fair value an unrealized holding gain of $5.9 million in 2004 has been recorded directly to other comprehensive income (see consolidated statements of changes in shareholders' equity).

Note 6 Accounts Receivable, Net

Accounts receivable, net, consists of the following:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Accounts receivable — trade	$ 162 775	$ 130 821
Allowance for doubtful accounts	(1 492)	(3 115)
Total	$ 161 283	$ 127 706

Development of allowance for doubtful accounts is as follows:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Beginning balance	$ 3 444	$ 2 913	$ 4 648	$ 2 321
New and additional allowances	1 001	837	2 615	5 955
Write-offs and reversals	(2 953)	(179)	(4 350)	(3 616)
Disposal of subsidiary	—	(127)	—	(12)
Ending balance	$ 1 492	$ 3 444	$ 2 913	$ 4 648
Related to:				
Accounts receivable, net	$ 1 492	$ 3 115	$ 2 472	$ 4 608
Unbilled and other receivables	—	329	314	—
Assets of discontinued operations	—	—	127	40
Total	$ 1 492	$ 3 444	$ 2 913	$ 4 648

Note 7 Other Current Assets

Other current assets consist of the following:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Prepaid operating expenses	$ 13 053	$ 19 186
Spare parts, consumables and supplies	12 840	11 348
Prepaid taxes	15 821	11 017
Produced oil, not lifted	5 037	4 569
Advances to agents	723	5 123
Other	13 032	11 367
Total	$ 60 506	$ 62 610

The Company had $616.5 million and $639.5 million in property and equipment under UK leases at December 31, 2004 and 2003, respectively (see Note 19).

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.

Note 8 Property and Equipment, Net

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

(In thousands of dollars)	December 31, 2004	December 31, 2003
Seismic vessels and equipment	$ 435 622	$ 384 294
Production vessels and equipment	680 737	679 748
Fixtures, furniture and fittings	18 383	11 786
Buildings and other	4 412	3 890
	1 139 154	1 079 718
Accumulated depreciation	(130 146)	(19 535)
Total	$ 1 009 008	$ 1 060 183

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 presented on a combined basis.

The following table summarizes depreciation expense:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Depreciation expense, net of amounts capitalized into multi-client library	$106 629	$18 206	$121 485	$154 204
Depreciation expense capitalized into multi-client library	3 982	1 329	11 766	31 528

Significant impairment charges were recorded in the ten months ended October 31, 2003 and the year ended December 31, 2002 related to property and equipment. See Note 4.

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:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Completed surveys:		
Completed during 1998, and prior years	$ 6 614	$ 37 424
Completed during 1999	20 158	40 402
Completed during 2000	21 976	40 140
Completed during 2001	106 876	139 154
Completed during 2002	35 393	54 520
Completed during 2003	33 296	74 686
Completed during 2004	11 620	—
Completed surveys	235 933	386 326
Surveys in progress	8 756	21 679
Multi-client library	$ 244 689	$ 408 005

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

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Impairment charges (Note 4)	$ —	$ —	$ 90 053	$ 200 393
Amortization and impairment (from 2004) expense	208 468	33 347	148 399	195 954
Interest capitalized into multi-client library	1 461	375	2 083	4 841
Depreciation capitalized into multi-client library	$ 3 982	$ 1 329	$ 11 766	$ 31 528

Amortization expense for the year ended December 31, 2004, includes $48.8 million of additional non-sales related amortization. This amount includes $28.9 million in minimum amortization and $19.9 million of non-sales related amortization (impairment) to reflect reduced fair value of future sales on certain individual surveys. For the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended December 31, 2002, the Company recognized $0.0 million, $36.6 million and $37.4 million, respectively, in minimum amortization.

For informational purposes, the following shows the hypothetical application of the Company's minimum amortization requirements to the components of the existing multi-client library. These minimum amortization requirements are calculated as if there will be no future sales of these components.

(In thousands of dollars)	Minimum Future Amortizations
During 2005	$ 53 509
During 2006	61 863
During 2007	64 254
During 2008	51 794
During 2009	9 844
During 2010	3 425
Future minimum amortization	$ 244 689

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

Note 10 Intangible Assets, Net

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

(In thousands of dollars)	December 31, 2004	December 31, 2003
Existing technology	$ 30 548	$ 33 011
Existing contracts	16 772	17 600
Order backlog	5 401	5 401
Patents, royalties and licenses	659	85
Total cost	53 380	56 097
Accumulated amortization	(17 266)	(3 488)
Total	$ 36 114	$ 52 609

Intangible assets existing at December 31, 2004 and 2003 were primarily recognized in conjunction with the adoption of fresh start reporting, effective November 1, 2003. Total amortization expense related to these intangible assets was $13.8 million for the year ended December 31, 2004, $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 for the year ended December 31, 2002. The weighted remaining amortization period for intangible assets as of December 31, 2004 is 5.2 years, and the amortization expense related to these assets, under existing amortization plans, for the next five years is $11.0 million (2005), $6.3 million (2006), $4.1 million (2007), $3.5 million (2008) and $2.3 million (2009).

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 subsequent periods, the tax benefit will be recorded as a reduction of the carrying value of long-term intangible assets and certain favorable lease contracts existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. At December 31, 2004, the Company realized such deferred tax assets and accordingly recorded $3.3 million in reduction of the carrying amounts of intangible assets, which are reflected in the table above as reduction in gross costs (see Note 20).

Note 11 Other Long-Lived Assets

Other long-lived assets consist of the following:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Governmental grants and contractual receivables	$ 17 204	$ 16 772
Long-term receivables	14 945	6 947
Favorable lease contracts	10 444	13 806
Deferred debt issue costs	2 066	—
Total	$ 44 659	$ 37 525

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

The fair values 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 5 years) is recorded as an increase of lease expense as part of cost of sales.

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 subsequent periods, the tax benefit will be recorded as a reduction of the carrying value of long-term intangible assets and certain favorable lease contracts assets existing at adoption of fresh-start accounting until the value of such assets is reduced to zero. At December 31, 2004, the Company realized such deferred tax assets and accordingly recorded $1.0 million in reduction of the carrying amounts of favorable lease contracts (see Note 20).

Note 12 Accrued Expenses

Accrued expenses consist of the following:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Accrued employee benefits	$ 37 659	$ 30 199
Accrued vessel operating expenses	17 080	25 126
Customer advances and deferred revenue	12 070	12 614
Accrued commissions	9 683	5 088
Accrued interest expenses	3 394	2 658
Accrued severance and restructuring expenses	290	5 061
Accrued debt restructuring expenses	—	25 218
Other	35 080	41 372
Total	$ 115 256	$ 147 336

Accrued debt restructuring costs as of December 31, 2003 includes $22.7 million of excess cash 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	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Beginning balance	$ 5 061	$ 8 367	$ 1 215	$ —
Additional and adjustment of allowances	(632)	1 764	18 469	1 215
Severance and restructuring costs paid	(4 139)	(5 070)	(11 317)	—
Ending balance	$ 290	$ 5 061	$ 8 367	$ 1 215

Note 13 Other Long-Term Liabilities

Other long-term liabilities consist of the following:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Accrued liabilities UK leases (Note 19)	$ 79 344	$ 78 120
Pension liability (Note 21)	52 472	45 185
Asset retirement obligations ("ARO") (Note 2)	58 518	50 016
Tax contingencies	25 522	16 124
Other	3 794	8 218
Total	$ 219 650	$ 197 663

The following table presents changes in asset retirement obligations for the year ending December 31, 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003:

	Successor Company		Predecessor Company
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Balance at beginning of period	$ 50 016	$ 49 847	$ 59 767
Accretion expense	4 005	599	3 793
Liabilities settled in the period	—	(430)	—
Revision in estimated cash flow/fair value	4 497	—	(13 713)
Balance at end of period	$ 58 518	$ 50 016	$ 49 847

ARO liability as of December 31, 2004, includes $39.9 million relating to our Pertra oil and natural gas activity. When we sold Pertra to Talisman in March 2005, the buyer assumed this liability as part of the transaction. The remaining ARO liability relates mainly to the Banff field and will be settled at the end of the contract, currently expected to be not later than 2015.

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:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Short-term debt	$ 1 962	$ —
Current portion of long-term debt (Note 15)	17 828	18 512
Total	$ 19 790	$ 18 512

Note 15 Financial Restructuring and Long-Term Debt

Financial restructuring completed in 2003:

On July 29, 2003, the Company voluntarily filed a petition for protection under Chapter 11 of the United States Bankruptcy Code ("Chapter 11"). The filing was based on a financial restructuring plan that was pre-approved by a majority of banks and bondholders as well as a group of PGS' largest shareholders. PGS emerged from Chapter 11 November 5, 2003, just 100 days after filing. (See Note 3.)

Long-Term Debt.

Long-term debt consists of the following:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Unsecured:		
10% Senior Notes, due 2010	$ 745 949	$ 745 950
8% Senior Notes, due 2006	250 000	250 000
Libor + 1.15% Unsecured senior term loan	—	4 811
Secured:		
8.28% First Preferred Mortgage Notes, due 2011	98 920	109 119
Other loans, due 2005 — 2006	8 149	17 306
Total debt	1 103 018	1 127 186
Less current portion	(17 828)	(18 512)
Total long-term debt	$ 1 085 190	$ 1 108 674

Aggregate maturities of long-term debt as of December 31, 2004 are as follows:

Year of repayment:	December 31, 2004 *(In thousands of dollars)*
2005	$ 17 828
2006	263 231
2007	12 900
2008	14 040
2009	15 160
Thereafter	779 859
Total	$ 1 103 018

The 10% Senior Notes, due 2010 ("10% Notes") bear interest at 10% per annum payable semi-annually and mature in November 2010 with no required principal payments until maturity. The 10% Notes are callable beginning in 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 payment until maturity. 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 sheets because the monies will be used to make final debt service payment when the 8.28% Notes are retired. The 8.28% Notes are callable beginning in June 2006 and are callable thereafter at par plus a make whole premium based on U.S. treasury rates plus 0.375%

In May 2004, the Company repaid its 8-year, unsecured senior term loan of $4.8 million, which had an original maturity date in 2011.

Bank Credit Facilities

In March 2004, the Company entered into a secured $110.0 million credit facility consisting of a $70.0 million revolving credit facility and a $40.0 million letter of credit facility. The Company may 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 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 borrowing under the credit facility is LIBOR plus 2%. The credit facility is an obligation of PGS ASA and is guaranteed by certain material subsidiaries. The aggregate amount drawn on this letter of credit facility at December 31, 2004 was $15.0 million.

Short-Term Debt

Net short-term debt was $2.0 million as of December 31, 2004 of which $1.8 million relate to the purchase of the seismic vessel Falcon Explorer.

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 debt, to $1.5 billion. These debt agreements also include restrictions on: payment of dividends; ability to place liens on Company 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. Specifically, the Company is not allowed to pay dividends or make similar distribution until the 8% Notes are repaid.

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 has 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 the covenants in its loan and lease agreements and senior note indenture as of December 31, 2004, after giving effect to the waivers and amendments described above.

Pledged Assets

Certain seismic vessels and seismic equipment with a net book value of $55.2 million and $59.8 million at December 31, 2004 and 2003, respectively, are pledged as security on the Company's short-term and long-term debt. In addition *Petrojarl Varg* and the shares of KS *Petrojarl 1* AS and Golar-Nor Offshore AS, 98.5% owners of *Petrojarl 1*, are pledged as security for the $110 million bank credit facility. The book value of *Petrojarl Varg* and shares in KS *Petrojarl 1* AS and Golar-Nor Offshore AS totals $166.9 million at December 31, 2004.

Letter of Credit and Guarantees

The Company had aggregate outstanding letters of credit and related types of guarantees, not reflected in the accompanying consolidated financial statements, of $30.1 million and $31.0 million at December 31, 2004 and 2003, respectively.

Subsequent Events.

In February 2005 the Company established an additional overdraft facility of NOK 50 million as part of its Norwegian cash pooling system.

On March 8, 2005 the Company sent a notice of redemption relating to $175 million of its $250 million 8% Senior Notes due 2006. On April 7, 2005, 8% Senior Notes in the amount of $175 million were redeemed at a redemption price equal to 102.00% of the principal amount of such notes, plus accrued and unpaid interest to the redemption date.

Note 16 Interest Expense

Interest expense consists of the following:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Interest expense, gross	$ (112 272)	$ (17 245)	$ (92 504)	$ (143 168)
Interest on trust preferred securities	—	—	(8 536)	(14 974)
Interest capitalized	1 461	375	2 083	4 841
Total interest expense	$ (110 811)	$ (16 870)	$ (98 957)	$ (153 301)

Note 17 Other Financial Items, Net

Other financial items, net, consist of the following:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Interest income	$ 4 840	$ 1 050	$ 4 467	$ 4 214
Foreign currency loss	(8 024)	(5 208)	(4 286)	(10 915)
Sale of shares in Aqua Exploration Ltd	1 500	—	—	—
Gain on TES	—	—	—	45 264
Other	(9 177)	(106)	(1 653)	(4 771)
Financial expense, net	$ (10 861)	$ (4 264)	$ (1 472)	$ 33 792

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 settled.

Other includes additional rental paid relating to UK leases of $6.3 million for the year ended December 31, 2004, $4.9 million for the two months ended December 31, 2003, $1.5 million for the ten months ended October 31, 2003 and $3.9 million for the year ended December 31, 2002 (see Note 19).

Note 18 Financial Instruments

Fair Values of Financial Instruments.

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

	December 31, 2004		December 31, 2003	
(In thousands of dollars)	Carrying Amounts	Fair Values	Carrying Amounts	Fair Values
Long-term debt	$1 103 018	$1 218 386	$1 127 186	$1 185 313

The fair values of the long-term debt instruments are estimated using quotes obtained from dealers in such financial instruments.

Interest Rate Exposure.

The Company engages from time-to-time in interest rate derivatives. As at December 31, 2004, the Company had outstanding interest swap agreements in the aggregate notional amount of $10.3 million that do not qualify for hedge accounting. The aggregate market value of these agreements at December 31, 2004 was approximately ($0.5) million.

Commodity Derivative.

The Company operates 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 2004 (combined) was 5,317,134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2004 and 2003, we did not have any outstanding 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. Of the total amount sold forward, 250,000 barrels sold forward at an average price of $29.91 per barrel was not yet delivered at December 31, 2004 and was delivered in early January 2005. Estimated fair value of the contract at December 31, 2004 was a net liability of $2.6 million, which is included as accrued expenses in the consolidated balance sheets and revenues products in the consolidated statements of operations, based on marked to market rates.

Note 19 Commitments and Contingencies

Leases.

The Company has operating lease commitments expiring at various dates through 2015. The Company also has capital lease commitments, primarily for onshore-based seismic equipment, expiring at various dates through 2008. Future minimum payments related to non-cancelable operating and capital leases, with lease terms in excess of one year, at December 31, 2004 are as follows:

	December 31, 2004	
(In thousands of dollars)	Operating Leases	Capital Leases
2005	$ 36 436	$ 27 364
2006	22 818	21 224
2007	22 612	6 904
2008	22 609	6 632
2009	21 283	—
Thereafter	37 875	—
Total	$ 163 633	62 124
Imputed interest		(3 385)
Net present value of capital lease obligations		58 739
Current portion of capital lease obligations		(25 583)
Long-term portion of capital lease obligations		$ 33 156

Future minimum payments related to non-cancelable operating leases reflect $7.1 million in sublease income for 2005, 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:

(In thousands of dollars)	December 31, 2004
Marine seismic and support vessels	$ 7 135
Onshore seismic equipment	213
FPSO shuttle and storage tankers	60 000
Operations computer equipment	63
Buildings	95 714
Fixtures, furniture and fittings	508
Total	$ 163 633

Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above, is the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. The Company is required to charter the vessel for as long as *Ramform Banff* produces the Banff field, which could extend to 2015 depending on the customer/field operator. The maximum payment for the charter through 2015 is $119.4 million of which only the next six months charter is included in the table above.

Rental expense for operating leases, including leases with terms of less than one year, was $59.4 million for the year ended December 31, 2004, $12.2 million for the two months ended December 31, 2003, $76.3 million for the ten months ended December 31, 2003 and $105.4 million for the year ended December 31, 2002. Rental expense for operating leases are net of sub-lease income related to time charter of FPSO shuttle tankers to a third party amounting to $10.3 million for the year ended December 31, 2004, $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 for the year ended December 31, 2002.

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 *Petrojarl Foinaven*; and the production equipment for 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 ("Interest Rate Differential"). There are no limits on either of these indemnities. Reference is also made to the description in Note 2 — UK Leases.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. The Company understands that the UK Inland Revenue ("Inland Revenue") has generally deferred agreeing to the capital allowances claimed under such leases pending the outcome of a case that was appealed to the UK House of Lords, the highest UK court of appeal. In that case, the Inland Revenue was challenging capital allowances associated with a defeased lease. In November 2004, the House of Lords ruled in favor of the taxpayer and rejected the position of the Inland Revenue. The Company has been informed that in 2005 the Inland Revenue has accepted the lessors' claims to capital allowances for three of the Company's UK leases.

As a result of the November 2004 decision by the House of Lords, 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.

For fresh start reporting purposes, the Company 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 recorded a 16.7 million British pounds ($28.3 million) liability as of November 1, 2003 in accordance with the requirements of SOP 90-7. At December 31, 2004 and 2003 this liability amounted to $32.1 million and $29.5 million, respectively. As noted above, the House of Lords rejected the appeal by the Inland Revenue in a similar case. As a result, the Company expects to reduce this liability as the Inland Revenue accepts the lessors' claims for capital allowances associated with the Company's defeased UK leases.

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).

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 ("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 based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, 27.4 million British pounds (approximately $48.6 million) at December 31, 2003 and 24.6 million British pounds (approximately $47.2 million) at December 31, 2004.

Currently, interest rates are below the Assumed Interest Rates. Based on forward market rates for Sterling LIBOR the net present value, using an 8% discount rate, of the Additional Required Rental Payments aggregated 29.6 million British pounds (approximately $56.9 million) as of December 31, 2004. Of this amount, 1.0 million British pounds (approximately $2.0 million) was accrued at December 31, 2004, in addition to the remaining fresh start liability as described above.

Additional Required Rental Payments were $6.3 million for the year ended December 31, 2004, $4.9 million for the two months ended December 31, 2003, $1.5 million for the ten months ended October 31, 2003 and $3.9 million for the year ended December 31, 2002.

Note 20 Income Taxes

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

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Current taxes:				
Norwegian	$ (5)	$ 394	$ 6 639	$ —
Foreign	20 761	1 558	15 373	23 801
Deferred taxes:				
Norwegian	24 534	(1 575)	2 025	158 846
Foreign	2 729	(4 226)	(3 943)	3 243
Total	$ 48 019	$ (3 849)	$ 20 094	$ 185 890
Classification in Consolidated Statements of Operations:				
Income tax expense (benefit)	48 019	(3 849)	21 911	185 890
Fresh start adoption	—	—	(1 817)	—
Total income tax expense (benefit)	$ 48 019	$ (3 849)	$ 20 094	$ 185 890

The total income tax expense (benefit) for the year ended December 31, 2004, the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended 2002 include $41.0 million, $3.1 million, $182.9 million and $61.1 million, respectively, in valuation allowances related to deferred tax assets (see table below).

The total income tax expense (benefit) for the year ended December 31, 2004, the ten months ended October 31, 2003 and the year ended December 31, 2002 include $9.5 million, $2.0 million and $15.0 million, respectively, of provisions related to uncertainties regarding outstanding tax issues. See Note 13 for long-term tax contingencies.

The total income tax expense (benefit) for the year ended December 31, 2002 excludes $9.6 million related to discontinued operations.

The Company evaluates the need for valuation allowances related to its deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. 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.

Changes in valuation allowance are as follows:

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Balance at the beginning of the period	$ 368 550	$ 365 439	$ 182 581	$ 121 498
Current year additions	41 021	3 111	182 858	61 083
Decrease of valuation allowance related to utilization of pre-reorganization deferred tax assets(a)	(4 286)	—	—	—
Balance at the end of the period	$ 405 285	$ 368 550	$ 365 439	$ 182 581

(a)The decrease of valuation allowance related to the utilization of tax benefits from pre-reorganization temporary differences and losses carried forward (for which a valuation allowance was provided at the date of reorganization) resulted in a corresponding decrease of intangible assets (see Notes 10 and 11). Of the total valuation allowance as of December 31, 2004, $358.1 million relates to pre-reorganization amounts and will, if the related deferred tax assets are subsequently recognized, be allocated to reduce intangible assets and certain favorable lease contracts (included in other long-lived assets) or directly to contributed capital.

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	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Income (loss) from continuing operations before income taxes, minority interest and cumulative effect of change in accounting principles:				
Norwegian	$ (125 179)	$ (16 755)	$ 623 654	$ (547 030)
Foreign	35 421	3 198	(46 052)	(76 205)
Total	(89 758)	(13 557)	577 602	(623 235)
Norwegian statutory rate	28%	28%	28%	28%
Expense (benefit) for income taxes at statutory rate	(25 132)	(3 796)	161 729	(174 506)
Increase (reduction) in income taxes from:				
Foreign earnings taxed at other than statutory rate	(7 612)	(440)	(2 057)	(8 023)
Petroleum surtax(a)	12 343	(1 619)	5 908	(2 503)
Non-taxable gain on debt discharge	—	—	(351 078)	—
Exit Norwegian shipping regime 2002	—	—	—	78 859
Prior year adjustment regarding exit Norwegian shipping regime 2001	—	—	—	82 141
Other prior year adjustments	3 047	—	—	—
Goodwill impairment	—	—	—	48 462
Gain (loss) from local currency other than reporting currency	(2 578)	(1 495)	372	91 020
Non-creditable foreign taxes and other permanent items	26 930	390	22 362	9 357
Deferred tax asset valuation allowance	41 021	3 111	182 858	61 083
Total income tax expense (benefit)	$ 48 019	$ (3 849)	$ 20 094	$ 185 890

(a) Pertra's income from oil activities on the Norwegian Continental Shelf is taxed according to the Norwegian Petroleum Tax Law, which includes a surtax of 50% in addition to the Norwegian corporate tax of 28%.

Deferred tax assets and liabilities are summarized as follows:

	December 31, 2004		December 31, 2003	
(In thousands of dollars)	Asset	Liability	Asset	Liability
Current assets	$ (3 036)	$ 1 038	$ (11 803)	$ 2 188
Property, equipment and other long-lived assets	(23 384)	37 002	(55 035)	120 585
Tax losses carried forward	(262 458)	—	(326 622)	—
Deferred gain (loss)	(57 721)	32 971	(63 419)	37 583
Tax credits	(2 893)	—	(3 855)	—
Expenses deductible when paid	(84 853)	—	(31 208)	—
Other temporary differences	(6 072)	—	(37 833)	13 773
Total deferred tax (asset) liability before valuation allowance	(440 417)	71 011	(529 775)	174 129
Deferred tax asset valuation allowance	405 285		368 550	
Deferred tax (asset) liability	$ (35 132)	$ 71 011	$ (161 225)	$ 174 129
Net deferred tax liability — Norwegian		35 514		10 980
Net deferred tax liability — Foreign		365		1 924
Net deferred tax liability		$ 35 879		$ 12 904
Classification in Consolidated Balance Sheets:				
Short-term deferred tax liability		$ 761		$ 2 166
Long-term deferred tax liability		35 118		10 738
Net deferred tax liability		$ 35 879		$ 12 904

Norwegian tax loss carried forwards of $471.6 million expire at various dates from 2011 through 2014. Tax loss carried forwards in the UK, Singapore and other totaling $353.0 million do not expire. US tax loss carried forward of $72.5 million expire between 2019 and 2025. 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 outside of Norway indefinitely. The Company has not calculated the tax effect associated with these unremitted earnings as it is not practicable to do so.

Until January 1, 2002 a foreign subsidiary was included in the Norwegian shipping tax regime. No deferred taxes were recognized on unremitted earnings in this subsidiary prior to the withdrawal from the regime as these earnings at that time were expected to be reinvested indefinitely within the regime. A subsequent decision in 2003 to exit with effect from 2002 resulted in recognition of deferred tax liabilities of $78.8 million. The Norwegian Central Tax Office (CTO) has not yet finalized the 2002 tax assessment in relation to withdrawal from the Norwegian shipping tax regime. The pending issue is related to fair value of the vessels involved. The Company based such exit values on third party valuations, while the CTO has raised the issue whether the Company's book values at December 31, 2001, would be more appropriate as basis for computing the tax effects of the exit. Any increase of exit values will result in an increase of taxable exit gain and a corresponding increase in basis for future tax depreciation. The Company estimates that if the CTO position is upheld, taxes payable for 2002, without considering mitigating actions, could increase by up to $24 million. The Company believes that its calculation basis for exit has been prepared using acceptable principles and will contest any adjustment to increase taxes payable.

Note 21 Pension Obligations

The Company has 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 that are sufficient to meet the applicable statutory requirements. At December 31, 2004, 1,069 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:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Projected benefit obligations at beginning of period (a)	$ 101 855	$ 90 478
Service cost	10 198	1 204
Interest cost	5 145	1 207
Employee contributions	968	—
Payroll tax	178	1 359
Actuarial (gain) loss, net	(9 532)	3 338
Benefits paid	(1 212)	—
Exchange rate effects	10 196	4 269
Projected benefit obligations at end of year	$ 117 796	$ 101 855

(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:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Fair value of plan assets at beginning of period (b)	$53 332	$50 134
Adjustment at beginning of year	(1 214)	—
Return on plan assets	4 130	819
Employer contributions	8 383	504
Employee contributions	968	—
Benefits paid	(1 212)	—
Exchange rate effects	7 178	1 875
Fair value of plan assets at end of year	$71 565	$53 332

(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:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Funded status	$(46 232)	$(48 523)
Unrecognized actuarial (gain) loss	(6 021)	3 338
Additional minimum liability	(219)	—
Net amount recognized as accrued pension liability	$(52 472)	$(45 185)

The accumulated benefit obligation for all defined benefit pension plans was $104.3 million and $81.4 million as of December 31, 2004 and 2003, respectively.

Assumptions used to determine benefit obligations:

	2004		2003	
	Norway	UK	Norway	UK
Discount rate	5.3%	5.3%	6.0%	5.3%
Return on plan assets	6.3%	7.5%	7.0%	7.5%
Benefit increase	3.0%	3.0%	3.0%	4.7%
Annual adjustment to pensions	3.0%	3.0%	3.0%	3.0%

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 are summarized as follows.

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Service cost	$ 10 198	$ 1 204	$ 7 145	$ 7 928
Interest cost	5 145	1 207	3 247	3 108
Expected return on plan assets	(4 130)	(819)	(2 977)	(3 439)
Amortization of actuarial loss (gain)	16	(80)	403	1 908
Amortization of prior service cost	—	—	3	2
Amortization of transition obligation	—	—	17	15
Adjustment to minimum liability	198	—	—	—
Administration cost	99	—	—	—
Payroll tax	949	266	397	367
Net periodic pension cost	$ 12 475	$ 1 778	$ 8 235	$ 9 889

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

	December 31,	
(In thousands of dollars)	2004	2003
Projected benefit obligation	$ 112 727	$ 89 819
Accumulated benefit obligation	100 167	72 151
Fair value of plan assets	67 147	45 074

The Company's pension plan asset allocation at December 31, 2004 and 2003, by asset category, are presented by major plan group as follows:

	December 31, 2004		December 31, 2003		
(In thousands of dollars)	Norway[(1)]	UK	Norway[(1)]		UK
Fair value of plan assets	$ 40 111	$ 31 454	$ 15 280	$ 14 907	$ 23 145
Bonds	69%	—	62%	57%	—
Equity securities	16%	92%	13%	14%	74%
Real estate	12%	—	12%	13%	—
Other	3%	8%	13%	16%	26%
Total	100%	100%	100%	100%	100%

(1) Prior to 2004, the plans in Norway were with two separate companies. These companies merged in 2004.

For the Norwegian plans, the average target allocation for plan assets are 10-25% in equity securities, 50-70% in bonds, 10-15% in real estate and 3-10% in other.

The Company expects to contribute approximately $7.9 million to its pension plans in 2005. Total pension benefit payments expected to be paid to participants from the plans are as follows:

(In thousands of dollars)	
2005	$ 1 431
2006	1 500
2007	1 620
2008	1 777
2009	1 991
2010 through 2014	16 494

Substantially all employees not eligible for coverage under the defined benefit plans described above are eligible to participate in pension plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans. Under the Company's U.S. defined contribution 401(k) plan, essentially all U.S. employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 100% of compensation, subject to IRS and plan limitations, on a pre-tax basis, with a 2004 statutory cap of $13,000 ($16,000 for employees over 50 years). Employee pre-tax contributions are matched by the Company as follows: the first 3% are matched at 100% and the next 2% are matched at 50% of compensation. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $1.2 million for the year ended December 31, 2004, $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 the year ended December 31, 2002. Contributions to the plan by employees for these periods were $3.1 million, $0.6 million, $2.7 million and $3.8 million, respectively. Aggregate employer and employee contributions under the Company's other plans for the year ended December 31, 2004, the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended December 31, 2002, totalled $0.8 million and $0.4 million (2004), $0.1 million and $0.1 million (two months 2003), $2.1 million and $0.3 million (ten months 2003) and $7.4 million and $3.0 million (2002).

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 relating to share options for the Company's key employees and directors were also cancelled. No new option agreements have been established since the restructuring. During the period in which the share-based compensation plan was active, the exercise price of each award equaled the market price of the Company's shares on the grant date. The vesting period for granted options ranged from approximately three years to approximately three and one-half years. Once vested, the exercisable life of the options was generally a two-year period, with certain options granted during 2000 and thereafter exercisable over a three-year period.

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

	December 31, 2003		December 31, 2002	
(In thousands of options, except exercise prices)	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding at beginning of year	4 973.5	NOK 135	8 635.4	NOK 142
Granted	—	—	—	—
Exercised	—	—	—	—
Forfeited/cancelled	(4 973.5)	NOK 135	(3 661.9)	NOK 151
Outstanding at December 31	—	—	4 973.5	NOK 135
Weighted average grant fair value of options granted during year		—		—

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:

(In thousands of dollars, except per share amounts)	Successor Company Year Ended December 31, 2004	Successor Company Two Months Ended December 31, 2003	Predecessor Company Ten Months Ended October 31, 2003	Predecessor Company Year Ended December 31, 2002
Net income (loss), as reported	$ (134 730)	$ (9 953)	$ 557 045	$ (1 174 678)
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)
Pro forma, net income (loss)	$ (134 730)	$ (9 953)	$ 551 940	$ (1 184 482)
Net income (loss) per share:				
Basic and diluted — as reported	$ (6.74)	$ (0.50)	$ 5.39	$ (11.37)
Basic and diluted — pro forma	$ (6.74)	$ (0.50)	$ 5.34	$ (11.46)

The Company did not grant any share options during the years ended December 31, 2004, 2003 or 2002.

Note 23 Acquisitions and Dispositions

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 (28%) and Norsk Hydro (42%). The Company's 30% partner is the Norwegian government's State Direct Financial Interest. The Company's FPSO vessel, *Petrojarl Varg*, has been in production on the Varg field since December 1998.

In December 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 impairment. The Company received proceeds of $20.2 million at the closing date and received an additional $3.8 million in 2003 upon settlement of the working capital adjustment. Furthermore, the Company recorded additional gains of $3.0 million and $1.5 million relating to contingent events for the years ended December 31, 2004 and 2003, respectively. In addition, the Company recorded fair value of $2.0 million related to such contingent events in connection with its adoption of fresh start reporting as of November 1, 2003. The Company is eligible to receive an additional $3.0 million upon the occurrence of certain contingent events through 2010.

In February 2003, the Company sold its Atlantis oil and gas activities to Sinochem and received proceeds 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.

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

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

	Successor Company	Predecessor Company			
	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002		
(In thousands of dollars)	Tigress	Tigress	Tigress	Atlantis	Production Services
Revenue	$ 137	$ 1 107	$ 1 684	$ 23 452	$ 181 302
Operating expenses before depreciation, amortization, impairment and other operating income and expenses	(264)	(2 433)	(2 796)	(15 836)	(176 642)
Depreciation and amortization	—	(707)	(913)	—	(455)
Impairment of long-term assets	—	—	—	(169 284)	—
Other operating income and expenses	—	(512)	—	—	—
Total operating expenses	(264)	(3 652)	(3 709)	(185 120)	(177 097)
Operating profit (loss)	(127)	(2 545)	(2 025)	(161 668)	4 205
Financial expenses and other financial items, net	24	(1 237)	(1 278)	1 545	(74)
Income (loss) before income taxes and change in accounting principle	$ (103)	$ (3 782)	$ (3 303)	$ (160 123)	$ 4 131
Capital expenditures of discontinued operations	$ —	$ 118	$ 135	$ 77 126	$ 103

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

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Income (loss) from discontinued operations before income taxes and change in accounting principles	$ —	$ (103)	$ (3 782)	$ (159 295)
Loss on disposal	—	(32)	—	(31 580)
Additional proceeds	3 048	—	1 500	—
Income tax benefit (expense)	—	—	—	(9 588)
Goodwill impairments SFAS 142, net of tax	—	—	—	(674)
Loss from discontinued operations, net of tax	$ 3 048	$ (135)	$ (2 282)	$ (201 137)

Operating expenses relating to discontinued operations includes corporate management fees based on actual charges to these entities. For continuing operations such fees are presented in the segment for Reservoir/Shared Services/Corporate (Note 26). Allocation of interest expense to discontinued operations is based on actual interest charged to the respective entities.

Subsequent Event:

On February 1, 2005, the Company signed an agreement to sell its wholly-owned subsidiary Pertra AS to Talisman Energy (UK) Ltd., and the transaction closed on March 1, 2005. The sales price was approximately $155 million with an estimated gain of approximately above $140 million, based on book-value of net assets as of December 31, 2004. We do not expect to incur any taxes from this transaction. The Pertra operations up to March 1, 2005 will be presented as discontinued operations in the consolidated financial statements for 2005. See Note 26 for selected financial information for Pertra for the years ended December 31, 2004, 2003 and 2002.

Assets and liabilities relating to Pertra as of December 31, 2004 and 2003 were as follows:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Cash and cash equivalents	$ 13 423	$ 16 437
Accounts receivable, net	7 406	(6)
Other current assets	15 916	5 242
Property and equipment, net	937	44
Oil and natural gas assets, net	70 940	33 523
Other long-lived assets	12 024	11 828
Total assets	$ 120 646	$ 67 068
Accounts payable	$1 624	$3
Accrued expenses	8 720	11 702
Deferred tax liabilities, current	761	2 166
Income taxes payable	—	3 587
Other long-term liabilities	39 942	32 764
Deferred tax liabilities, long-term	34 752	8 813
Total liabilities	$ 85 799	$ 59 035

Note 24 Related Party Transactions

At December 31, 2003 and 2002, 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 shares as Walter Herwig AS was de-merged) and chartered three vessels from that company in 2003 and 2002. Total lease expense recognized during the two months ended December 31, 2003, the ten months ended October 31, 2003 and the year ended December 31, 2002 on these vessels was $1.1 million, $6.4 million and $8.9 million, respectively, while there were no lease expense recognized during 2004.

As of December 31, 2004, the Chairman of the Board, Jens Ulltveit-Moe, through Umoe AS, controlled a total of 1,012,444 shares in Petroleum Geo-Services 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 was also chartering the MT Nordic Yukon up to 2003, from PGS on a time charter contract and paid $10.3 million, $20.1 million and $20.5 million to PGS under these contracts in 2004, 2003 and 2002, respectively. PGS charters the vessels from an independent third party. The vessels were chartered by PGS to provide shuttle services for 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 $0.7 million, $2.4 million and $1.8 million to Knutsen under this contract in 2004, 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.

Note 25 Investments in Associated Companies

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

	Successor Company		Predecessor Company	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Corporations and limited partnerships:				
Geo Explorer AS	$ 26	$ 119	$ 1 425	$ 142
Atlantic Explorer (IoM) Ltd	(80)	—	—	—
FW Oil Exploration LLC	—	—	—	(5 845)
Ikdam Production SA	722	81	162	(3 561)
Triumph Petroleum	—	—	(813)	(2 237)
Total	$ 668	$ 200	$ 774	$ (11 501)

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

(In thousands of dollars)	Book Value December 31, 2003	Share of Income 2004	Paid-In Capital/ (Dividends) 2004	Equity Transactions 2004(a)	Book Value December 31, 2004	Ownership Percent as of December 31, 2004
Corporations and limited partnerships:						
Geo Explorer AS	$ 3 174	$ 26	$ (3 018)	$ —	$ 182	50.0%
Atlantic Explorer (IoM) Ltd	112	(80)	—	—	32	50.0%
Ikdam Production, SA	4 690	722	—	(1)	5 411	40.0%
General partnerships	94	—	—	1	95	
Total	$ 8 070	$ 668	$ (3 018)	$ —	$ 5 720	

(a) Includes foreign currency translation differences.

Note 26 Segment and Geographic Information

In 2004 we managed our 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 onshore multi-client library;
- Production, which owns and operates four harsh environment FPSOs in the North Sea; and
- Pertra, a small oil and natural gas company that owns 70% of and was operator for PL 038 on the Norwegian Continental Shelf ("NCS") and also owns participating interests in six additional NCS licenses without current production.

Pertra was sold to Talisman in March 2005 and will be reported as discontinued operations in the 2005 financial statements.

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 (PL 038), which is 70% owned and operated by Pertra, is producing using the *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 Reservoir/Shared Services/Corporate. Significant charges, which do not relate specifically to the operations of any one segment, such as debt restructuring costs, are also presented as Reservoir/Shared Services/Corporate. Information related to discontinued operations during any period presented has been separately aggregated. Affiliated sales are made at prices that approximate market value. Interest and income tax expense is not included in the measure of segment performance.

Information by business segment is summarized as follows:

(In thousands of dollars)	Marine Geo-physical	Onshore	Production	Pertra	Reservoir/ Shared Services/ Corporate	Elimination of Affiliated Sales	Total
Revenue, unaffiliated companies:							
2004 (Successor)	$ 561 898	$ 133 161	$ 237 815	$ 184 134	$ 12 460	$ —	$1 129 468
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
Revenue, includes affiliates:							
2004 (Successor)	$ 570 805	$ 133 161	$ 298 202	$ 184 134	$ 20 852	$ (77 686)	$1 129 468
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)	592 640	118 698	306 645	32 697	16 022	(23 471)	1 043 231
Depreciation and amortization:							
2004 (Successor)	$ 241 712	$ 39 885	$ 44 561	$ 38 965	$ 3 239	$ —	$ 368 362
2003 (Successor — two months)	39 351	6 224	8 112	743	1 269	—	55 699
2003 (Predecessor — ten months)	191 215	29 425	43 418	30 826	6 692	—	301 576
2002 (Predecessor)	247 933	28 408	70 958	12 695	7 509	—	367 503
Impairment of long-lived assets:							
2004 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
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
Other operating (income) expense, net:							
2004 (Successor)	$ (13)	$ 9	$ —	$ —	$ 8 116	$ —	$ 8 112
2003 (Successor — two months)	1 189	38	—	—	(175)	—	1 052
2003 (Predecessor — ten months)	8 107	266	—	—	12 951	—	21 324
2002 (Predecessor)	1 341	2 625	—	—	4 521	—	8 487
Operating profit (loss):							
2004 (Successor)	$ (34 967)	$ (4 544)	$ 77 769	$ 28 120	$ (29 102)	$ (1 593)	$ 35 683
2003 (Successor — two months)	583	1 740	11 878	(3 198)	(301)	—	10 702
2003 (Predecessor — ten months)	(55 923)	14 390	66 548	17 236	(32 426)	—	9 825
2002 (Predecessor)	(188 532)	(21 791)	(246 601)	(4 204)	(22 481)	(5 000)	(488 609)
Loss from discontinued operations, net of tax:(a)							
2004 (Successor)	$ —	$ —	$ 3 048	$ —	$ —	$ —	$ 3 048
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)
Cumulative effect of change in accounting principles, net of tax							
2004 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
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, 2004 (Successor)	$ 235	$ —	$ 5 411	$ —	$ 74	$ —	$ 5 720
December 31, 2003 (Successor)	3 308	—	4 687	—	75	—	8 070
Assets:							
December 31, 2004 (Successor)	$ 795 102	$ 90 451	$ 710 521	$ 120 646	$ 135 433	$ —	$1 852 153
December 31, 2003 (Successor)	959 261	117 383	790 316	67 068	63 332	—	1 997 360
Additions to long-lived tangible assets:(b)							
2004 (Successor)	$ 87 742	$ 10 817	$ 988	$84 991	$ 5 088	$ (114)	$ 189 512
2003 (Successor — two months)	13 715	5 182	1 662	4 424	463	—	25 446
2003 (Predecessor — ten months)	71 299	21 965	(1 147)	29 741	1 349	—	123 207
2002 (Predecessor)	167 400	24 981	3 828	10 913	1 203	—	208 325
Capital expenditures on discontinued operations:(a)							
2004 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	118	—	—	—	—	—	118
2002 (Predecessor)	135	—	103	77 126	—	—	77 364

(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 for 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) are not necessarily indicative of the earnings of the related property and equipment during the period. The geographic classification of income statement amounts listed below is based upon location of performance or, in the case of multi-client seismic data sales, the area where the survey was physically conducted.

Information by geographic region is summarized as follows:

(In thousands of dollars)	Americas	UK	Norway	Asia/ Pacific	Africa	Middle East/Other	Elimination of Affiliated Sales	Total
Revenue, unaffiliated companies:								
2004 (Successor)	$ 267 054	$ 191 745	$ 336 949	$ 191 703	$ 112 503	$29 514	$ —	$ 1 129 468
2003 (Successor — two months)	49 164	30 743	33 087	35 175	20 784	3 418	—	172 371
2003 (Predecessor — ten months)	270 095	181 595	235 663	82 980	124 601	66 930	—	961 864
2002 (Predecessor)	235 010	275 706	227 104	154 821	80 393	70 197	—	1 043 231
Revenue, includes affiliates:								
2004 (Successor)	$ 267 054	$ 194 712	$ 343 736	$ 191 703	$ 112 503	$29 514	$ (9 754)	$ 1 129 468
2003 (Successor — two months)	49 164	31 067	35 429	35 175	20 784	3 418	(2 666)	172 371
2003 (Predecessor — ten months)	270 095	183 371	238 543	82 980	124 601	66 930	(4 656)	961 864
2002 (Predecessor)	235 610	278 611	230 022	154 851	80 393	70 197	(6 453)	1 043 231
Total assets:								
December 31, 2004 (Successor)	$ 343 484	$ 927 172	$ 469 675	$ 79 873	$ 21 211	$10 738	$ —	$ 1 852 153
December 31, 2003 (Successor)	430 972	870 941	539 935	111 484	20 567	23 461	—	1 997 360
Capital expenditures (cash):								
2004 (Successor)	$ 7 955	$ 40 812	$ 96 813	$ 1 975	$ —	$ 817	$ —	$ 148 372
2003 (Successor — two months)	5 464	1 005	9 294	222	—	—	—	15 985
2003 (Predecessor — ten months)	6 261	6 155	27 952	136	—	1 561	—	42 065
2002 (Predecessor)	10 776	17 073	28 415	192	—	279	—	56 735

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2004, 2003 and 2002.

For the years ended December 31, 2004, 2003 and 2002, customers exceeding 10% of the Company's total revenue were as follows (the table shows percentage of revenues accounted for by each of such customers, and the segments that had sales to the respective customers are marked with X):

	Years Ended December 31,						
	2004		2003			2002	
	25%	10%	19%	12%	10%	15%	11%
Segments serving customer (each % in each year represents a separate customer):							
Marine Geophysical	X	X	X	X	X	X	X
Onshore					X		
Production	X	X	X	X		X	X
Pertra	X		X				X
Reservoir/Shared Services/Corporate	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	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Interest, net of capitalized interest	$ 106 731	$ 19 619	$ 120 162	$ 112 543
Interest on trust preferred securities	—	—	—	10 377
Income taxes	29 751	4 951	8 145	15 938

The Company entered into capital lease agreements for new equipment aggregating $0.6 million for the ten months ended October 31, 2003 and $65.0 million for the year ended December 31, 2002. There were no new capital lease agreements during the two months ended December 31, 2003 or the year ended December 31, 2004.

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. PGS ASA 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	
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003	Year Ended December 31, 2002
Income Statement Data:				
Revenue	$ 257 609	$ 17 610	$ 244 605	$ 286 261
Operating loss	(4 761)	(26 009)	(4 238)	(52 245)
Net loss	(22 868)	(12 671)	(6 752)	(47 887)
Balance Sheet Data:				
Current assets	$ 116 910	$ 99 453	$ 141 008	$ 146 061
Non-current assets	190 874	148 951	123 182	157 137
Current liabilities	56 573	84 523	82 555	112 941
Non-current liabilities	327 199	408 479	416 699	385 920
Equity (deficit)	(75 988)	(244 598)	(235 064)	(195 663)

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			
	Year Ended December 31, 2004		Two Months Ended December 31, 2003		Ten Months Ended October 31, 2003		Year Ended December 31, 2002	
(In thousands of dollars)	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger
Income Statement Data:								
Revenue	$ 5 251	$ 5 258	$ 1 078	$ 1 084	$ 6 032	$ 6 003	$ 7 458	$ 7 421
Operating profit	5 090	5 098	(8 462)	(9 098)	5 885	5 857	7 295	7 259
Net income	1 042	1 048	(9 162)	(9 809)	1 738	1 708	2 094	2 058
Balance Sheet Data:								
Current assets	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-current assets	55 493	54 621	59 561	58 681	72 964	72 719	71 879	71 651
Current liabilities	6 625	6 624	6 252	6 252	7 616	7 616	5 864	5 864
Non-current liabilities	44 175	44 177	49 658	49 657	52 324	52 336	54 729	54 729
Equity	4 693	3 820	3 651	2 772	13 024	12 767	11 286	11 058

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. Approximately 75% of these interests were sold in 2004 for $2.4 million. 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 from this FPSO are eliminated in consolidation, but the expenses are presented gross for this supplemental presentation. As a result, the oil and natural gas results in this supplemental disclosure will not match the results in the consolidated statements of operations. The Company meets the significant activities requirement for 2004 and 2003, but did not meet the requirement for 2002. As a result, no 2002 information is presented. In addition, it is not considered material to the disclosure to separately present the changes in reserves or the changes in Standardized Measure for the Predecessor and Successor periods during 2004 and 2003.

Financial Results Related to Oil and Natural Gas Activities.

The Successor results of operations, capitalized costs and costs incurred are based on the successful efforts method of accounting for oil and natural gas activities. The Predecessor results of operations and costs incurred are based on the SEC full cost method. See Note 2 for the description of each method. These methods may create significant differences in results, primarily because of the capitalization policies of each method. As a result, the Successor and Predecessor results of operations, capitalized costs and costs incurred information are not comparable.

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

	Successor Company		Predecessor Company
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Oil revenues	$ 184 134	$ 9 544	$ 112 097
Production costs	93 036	6 354	62 296
Other operating costs	3 952	599	2 126
Accretion of asset retirement obligation	1 664	271	1 821
Exploration costs	20 062	4 344	—
Depletion, depreciation and amortization	38 965	743	30 826
Results of operations before tax	26 455	(2 767)	15 028
Income tax expense (benefit)	20 635	(2 159)	11 722
Results of operations	$ 5 820	$ (609)	$ 3 306

The above table does not include any amounts for allocated selling, general and administrative expense or finance income or expense.

Capitalized costs relating to oil and natural gas producing activities are set forth below:

(In thousands of dollars)	December 31, 2004	December 31, 2003
Capitalized Costs:		
Proved properties	$ 106 604	$ 30 262
Unproved properties	4 000	4 000
Accumulated depreciation, depletion and amortization	(39 664)	(739)
Net	$ 70 940	$ 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
(In thousands of dollars)	Year Ended December 31, 2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Exploration costs	$20 062	$13 262	$16 253
Development costs	76 342	4 375	10 318
Total costs incurred	$96 404	$17 637	$26 571

Proved Reserves and Standardized Measure

The estimates of proved oil and natural gas reserves for Pertra as of December 31, 2004 and 2003 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 estimates were reviewed by an independent reservoir engineering consultant. All of Pertra's proved reserves are located in the Norwegian North Sea. The reserve estimates as of December 31, 2004 and 2003 utilize oil prices of $40.24 and $29.97, respectively, per barrel (reflecting adjustments for oil quality). The Company's actual average sale price for oil produced in 2004 was $35.11 per barrel, compared to $29.37 per barrel in 2003.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. Reserve estimates are inherently imprecise, and estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The oil and natural gas proved reserve quantities and changes in reserve quantities, the Standardized Measure of Future Net Cash Flows from Proved Reserves (Standardized Measure) and the changes in Standardized Measure are presented for the years ended December 31, 2004 and 2003 and as of December 31, 2004 and 2003, respectively. A company is required to disclose this information when it has significant oil and natural gas exploration and production activities.

The following tables provide a roll-forward of total proved reserves for the years ended December 31, 2004 and 2003, as well as proved developed reserves at year end, as of the beginning and end of each respective year, the Standardized Measure as of December 31, 2004 and 2003 and the changes in Standardized Measure for the years ended December 31, 2004 and 2003:

Estimated Quantities of Reserves (Unaudited)

(In thousand barrels)	December 31, 2004	December 31, 2003
CRUDE OIL		
Proved Reserves:		
Beginning of the year	7 818	4 137
Extensions and discoveries	2 976	4 669
Revisions of previous estimates	—	3 067
Production	(5 317)	(4 056)
End of year	5 477	7 818
Proved Developed Reserves:		
Beginning of year	2 114	3 272
End of year	5 477	2 114

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

(In thousands of dollars)	December 31, 2004	December 31, 2003
Future cash inflows	$ 220 440	$ 234 300
Future production costs	108 253	109 010
Future development costs	—	12 900
Future abandonment costs	47 391	37 122
Future income taxes	51 762	59 906
Future net cash flows	13 034	15 362
Discount at 10% per annum	(2 288)	(369)
Standardized Measure	$ 15 322	$ 15 731

Changes in Standardized Measure (Unaudited)

(In thousands of dollars)	December 31, 2004	December 31, 2003
Standardized Measure at beginning of year	$ 15 731	$ 944
Revisions of reserves proved in prior years	—	49 280
Changes in prices and production costs	10 636	333
Changes in estimates of future development and abandonment costs	(4 847)	(10 760)
Net change in income taxes	1 757	(59 090)
Accretion of discount	1 573	94
Other, primarily timing of production	10 454	695
Extensions, discoveries and other additions, net of future production and development cost	58 216	75 102
Sales of oil and natural gas produced, net of production costs	(91 098)	(48 667)
Previously estimated development and abandonment costs incurred during the period	12 900	7 800
Net changes in Standardized Measure	(409)	14 787
Standardized Measure at end of year	$ 15 322	$ 15 731

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, 2004 and 2003, and the related consolidated statements of operations, changes in shareholders' equity (deficit), and cash flows for the year ended December 31, 2004 and the two months ended December 31, 2003 (Successor), and for the ten months ended October 31, 2003 and the year ended December 31, 2002 (Predecessor). These financial statements are the responsibility of the Company's Board of Directors and management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Petroleum Geo-Services ASA and subsidiaries as of December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for the year ended December 31, 2004 and the two months ended December 31, 2003 (Successor), and for the ten months ended October 31, 2003 and the year ended December 31, 2002 (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."

/s/ ERNST & YOUNG AS

Oslo, Norway
May 3, 2005

Board of Directors' Report and Financial Statements 2004

Norwegian Generally Accepted Accounting Principles

Petroleum Geo-Services ASA

Contents

The full version of PGS annual report (USGAAP) is available both in printed format and on the PGS web site at www.pgs.com during May 2005.

Board of Directors' Report

In 2004 PGS demonstrated excellent HSE and operating performance. Despite a difficult marine geophysical market in the first half of the year, negative impact from a labor conflict on the Norwegian Continental Shelf and damage to the main production riser on the Varg field, PGS delivered on its financial projections for the year.

PGS significantly improved its financial flexibility, reducing net interest bearing debt to below $1 billion at year-end, and realizing a further $150 million reduction from the sale of Pertra early 2005.

In November 2004 PGS completed the re-audit of its historical U.S. GAAP financial statements and achieved a re-listing of its ADSs on the New York Stock Exchange ("NYSE") in December. These achievements mark important milestones in delivering the commitments from the Chapter 11 restructuring in 2003 and normalizing PGS' communication with, and access to, capital markets.

The divestment of Pertra in March 2005 marks PGS' exit from a very successful Exploration & Production (E&P) venture which started in 2001. PGS was formed as an oil service company and with this exit from E&P, PGS will once again become fully focused on its oil service business with strategic focus on geophysics and floating production operations. We are industry leaders in both these areas, with strong credibility, market share, client relationships and technological expertise. The main goal for 2005 is to improve the return on these assets.

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

PGS, in 2004, managed its 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 onshore multi-client library
- Production, which owns and operates four harsh environment FPSOs in the North Sea
- Pertra, a small oil and gas company which owned 70% of and which is operator for Production License 038 ("PL038") on the Norwegian Continental Shelf ("NCS") and also held participating interests in six additional NCS licenses without current production

Pertra was sold to Talisman in March 2005 as described in a separate paragraph below and will be reported as discontinued operation starting with the 2005 financial statements.

Business headlines 2004

Main business achievements include:

- Continued strong HSE performance
- Strong operating uptime and regularity in all businesses, with the exception of the impact of a strike on the NCS and a riser damage on the Varg field
- Strong value creation through successful development and sale of Pertra
- Financial flexibility greatly improved through 2004 cash flow from operations and will further improve with cash proceeds from sale of Pertra
- Net interest bearing debt reduced from $1 071 million to $995 million at year end 2004. Further reduction of approximately $150 million early 2005 from sale of Pertra
- Completion of re-audit of U.S. GAAP financial statements and subsequent re-listing on NYSE
- Strong multi-client late sales and marine seismic contract performance during second half of 2004

Sale of Pertra to Talisman

On February 1, 2005, PGS signed an agreement to sell its wholly-owned subsidiary Pertra AS to Talisman. The transaction was closed March 1, 2005.

> – The divestment of Pertra in March 2005 marks PGS' exit from a very successful E&P venture

> – PGS continued its focus on the marine contract market in 2004

The sales price was approximately $155 million. PGS expects to recognize the Pertra operations from January 1, 2005 to closing and a sales gain totaling above $140 million as discontinued operations in its financial statements for 2005. PGS does not expect to incur any taxes from the transaction.

As part of the transaction, Talisman has agreed to split with PGS, on a 50/50 basis, revenues (on a post petroleum tax basis) from production of the Varg Field exceeding $240 million per year in 2005 and 2006.

Further, Talisman and PGS entered into an option agreement under which the PL038 license holders can change the existing termination provisions for the FPSO *Petrojarl Varg*. The option, if exercised, will at the discretion of the PL038 license holders allow production of the Varg field to be extended until 2010. The option is exercisable until February 1, 2006, and if exercised the license owners will have to make a payment of $22.5 million and guarantee a minimum of $190,000 per day as compensation for the use of *Petrojarl Varg*. PGS received $2.5 million at closing for granting this option. Under the existing contract between PL038 and PGS Production, *Petrojarl Varg* is currently producing the Varg field for a fixed base day rate of $90,000 and a variable rate of $6.30 per barrel produced. PGS has a right to terminate the agreement if the production of the Varg field falls below 15,700 barrels per day.

In PGS' 2004 financial statements, the revenues and expenses of Pertra are included in revenues and expenses in the consolidated statement of operations. In PGS' 2005 financial statements, the gain on sale and the revenues and expenses of Pertra will be reported as discontinued operations and all historical financial statements will be reclassified to report Pertra as discontinued operations. Also, as a consequence, the revenues on the *Petrojarl Varg* FPSO related to Pertra's 70% of the Varg field will be reclassified to external revenue instead of being eliminated as inter-segment revenues, thereby increasing significantly the revenues in Production included in PGS' consolidated statement of operations.

Markets and main businesses

Marine Geophysical
PGS is one of four major global participants in the marine 3D market, with a market share exceeding 30%. The PGS streamer acquisition fleet, totaling 10 vessels, with the six Ramform vessels in the high capacity segment, is the most modern in the industry.

The marine 3D market has experienced continued overcapacity over several recent years. Since 2001 and well into 2004 a strong increase in demand for contract seismic has been offset by a steep reduction of multi-client activity. In 2004, 3D multi-client activity in the industry reached its lowest levels in 10 years.

After a weak first half of 2004, the balance between capacity and demand improved significantly in the second half resulting in improved prices and margins and an improved industry order backlog situation. PGS' marine acquisition order backlog was $170 million at December 31, 2004 compared to $108 million at December 31, 2003.

PGS continued its focus on the contract market in 2004. Activity in the multi-client market was further reduced from 2003 and higher levels of pre-funding were achieved. At the same time, sales from the multi-client library increased substantially during the second half of 2004. Over time PGS expects to increase its multi-client investment from the very low 2004 levels.

Onshore
In the market for onshore seismic services PGS is a medium sized player among a large number of both regional and global players. Competition and strengths and weaknesses vary significantly from region to region. New entrants to the market, including, among others, Chinese companies, play a significant role, especially in Asia.

In 2004, PGS Onshore had all its active crews and its main market presence in North and South America. In 2004, Onshore continued acceptable operating performance building on strong project execution and management, but activity levels declined towards the end of the year due to the completion of one out of two large projects in Mexico. The activity level in domestic U.S. was high throughout the year and a third crew was added to this operating area.

Production
PGS is the market leader in operating contractor owned FPSOs in the UK and Norwegian sectors of the North Sea. The demand for these services is highly dependent on specific oil and gas development projects for small to medium sized oilfields.

The four FPSOs owned and operated by Production continued on their existing contracts throughout 2004.

In December 2003, the contract with Canadian Natural Resources ("CNR"), operator of the Banff and Kyle fields in the UK sector of the North Sea, was amended. Under the agreement, *Ramform Banff* will continue to produce the Banff field until the end of the field's life. The amended contract is production incentive based but contains a minimum day rate provision of $125 000 per day. Development work on the Banff field and the tie in of a well from the Kyle field increased *Ramform Banff* production slightly towards the end of 2004. Further tie-ins from Kyle are planned for 2005.

Petrojarl I is producing the Glitne field, operated by Statoil, in the Norwegian sector of the North Sea. PGS expects the producing life of the Glitne field to extend to 2007.

Petrojarl Varg is producing the Varg field (in PL038) operated by Pertra (sold to Talisman in 2005). PGS' successful development drilling programs in 2003 and 2004 have significantly increased both production levels and the expected life of the field. The FPSO is now expected to continue to produce the field beyond 2007. In 2004, a revised compensation structure was agreed between the PL038 owners and PGS providing a combination of a fixed day rate and a volume based production tariff. Following the sale of Pertra to Talisman, the PL038 owners have an option to change certain terms of the production contract against making certain payments to PGS as described above.

Petrojarl Foinaven is producing the Foinaven field, operated by BP, west of Shetland. The vessel is expected to produce the field beyond 2007.

Operating regularity was generally high in 2004. However, production on two of the FPSOs was negatively impacted by a labor conflict on the NCS causing a shut down of *Petrojarl I* from September 12 to October 29 and *Petrojarl Varg* from October 13 to October 26. In addition, production on the Varg field was reduced to approximately one half of normal production beginning November 5 due to a damaged main production riser. The field returned to normal production after a successful installation of a new riser on March 9, 2005.

Pertra

The sale of Pertra to Talisman was closed March 1, 2005 as described above. Pertra had significant drilling activity in 2004, with a rig working throughout the entire year. In total, five development wells were completed on the Varg field. In addition, one dry exploration well was drilled on the "Villmink" prospect in PL 038.

As a result of the development work, underlying field output levels increased substantially throughout the year. However, in the fourth quarter production was negatively affected by a shut down from October 13 to October 26, caused by the labor conflict on the NCS, and damage of the main production riser on November 5, limiting production to a daily maximum of approximately 15,000 barrels.

Pertra's total oil production was 5.3 million barrels in 2004 compared to 4.1 million barrels in 2003. Average realized oil price was $35.11 per barrel in 2004 compared to $29.37 in 2003.

Pertra was awarded participation in an additional six licenses on the NCS during 2004.

Financial results

Total revenues for 2004 were $1,135.5 million compared to $1,120.7 million in 2003, an increase of 1%. Pertra revenues increased by $65.1 million, but this increase was partly offset by a decrease of revenues in Marine Geophysical and Onshore and higher elimination of inter-segment revenues as described below.

Marine Geophysical 2004 revenues totaled $574.2 million, a decrease of $10.0 million, or 2%, from 2003. Revenues from contract seismic acquisition decreased $49.5 million from $348.1 million in 2003 to $298.6 million in 2004, primarily due to a close down of the Company's ocean bottom 2C crew in late 2003. Revenues from this crew amounted to $40.5 million in 2003. In addition, contract revenues were negatively impacted by a weak contract market in first half of 2004, and significant operating disturbances during completion of a large turn key project offshore India in second quarter. Multi-client late sales increased by $57.9 million, or 39%, to $206.0 million in 2004, reflecting overall high demand in the second half of the year. PGS' acquisition of multi-client data was further reduced and revenues from multi-client pre-funding decreased by $19.2 million, or 39%, from $49.7 million in 2003 to $30.5 million in 2004. Pre-funding as a percentage of cash investments in multi-client data increased to 96% in 2004 compared to 73% in 2003. In 2004 the fleet allocation (active vessel time) between contract and multi-client data acquisition was approximately 89%/11% compared to approximately 81%/19% in 2003.

Onshore revenues for 2004 totaled $133.2 million, a decrease of $20.8 or 14% from 2003. Onshore had significant activity in Alaska, Mexico and Saudi Arabia in 2003 while in 2004, Onshore had no activity in Saudi Arabia or Alaska. Additionally, activity in Mexico declined at the end of 2004 as one of the two large projects was completed in third quarter. Activity in domestic U.S. was strong both for PGS and the market in general.

Revenues for Production totaled $298.2 million in 2004, which was $4.8 million, or 2%, higher than 2003. *Petrojarl Foinaven* had revenues of $96.6 million in 2004 compared to $112.1 million in 2003, a reduction of 14%. This reduction relates primarily to a natural decline in the production

– In 2004 the fleet allocation between contract and multi-client data acquisition was approximately 89%/11%

level of the field. *Petrojarl I* had revenues of $61.3 million in 2004 compared to $67.7 million in 2003, a decrease of 9%, primarily due to natural field production decline. Production on *Petrojarl I* was shut down from September 12 to October 29 due to a labor conflict on the NCS, but the revenue impact was limited as PGS received force majeure compensation during the period. Revenues from *Ramform Banff* were $51.5 million in 2004 compared to $45.2 million in 2003, an increase of 14%, primarily due to a $3.7 million lump sum modification job for CNR and the introduction of a new production contract effective January 1, 2004. Production levels on *Ramform Banff* improved in the latter part of 2004 due to tie in of one well from the Kyle field and development work on Banff field wells. Revenues from *Petrojarl Varg* increased $19.3 million, or 28% to $87.1 million in 2004 compared to $67.8 million in 2003. The increase is due primarily to increased production, despite a shut down from October 13 to October 26 related to a labor conflict on the NCS and damage to the main production riser reducing production to approximately 50% of the field's potential starting November 5.

Pertra revenues in 2004 totaled $186.7 million, an increase of $65.1 million, or 54%, from 2003. The increase is primarily due to an increase in production from 4.1 million barrels in 2003 to 5.3 million barrels in 2004.

Operating costs, excluding depreciation, amortization and other (income) expense, totaled $708.0 million in 2004 compared to $641.6 in 2003, an increase of $66.4 million. The increase relates primarily to increased operating costs for Pertra due to the significant increase in production and increased well intervention and geological and geophysical costs, which increased operating costs by $47.5 million. Marine Geophysical increased operating costs by $29.4 million, mainly as a result of a reduction of cost capitalized as multi-client investments (reduced by $36.7 million) and general cost increase driven by unfavorable change in currency rates and fuel prices, partially offset by the effect of close down of the ocean bottom 2C crew in late 2003. Production operating cost increased $8.8 million, primarily due to increased material purchases billed to customer (on *Ramform Banff*), a weakening of the U.S dollar exchange rate (which increases the reported U.S. dollar cost for Production since a significant part of these are incurred in British Pound Sterling and Norwegian Kroner) and increased maintenance expense. Maintenance investments in Production are expensed as incurred. Onshore reported a $1.0 million reduction of operating costs. Elimination of inter-segment revenues and cost (reduces consolidated revenues and operating costs), increased by $23.9 million and $22.3 million, respectively, primarily due to increased payments from Pertra to Production for the use of *Petrojarl Varg*.

Adjusted EBITDA[1] for 2004 was $427.5 million compared to $479.1 million in 2003, a decrease of $51.6 million or 11%. Marine Geophysical Adjusted EBITDA decreased by $39.4 million, Onshore Adjusted EBITDA decreased by $20.0 million, and Adjusted EBITDA for Production decreased by $4.0 million. Pertra Adjusted EBITDA increased $17.5 million.

Depreciation and amortization for 2004 was $327.0 million compared to $305.4 million in 2003, an increase of $21.6 million, or 7%. Ordinary gross depreciation expense decreased by $5.2 million, or 3%, to $157.7 million in 2004. Pertra depreciation increased $23.0 million, primarily due to increased production and a charge of $11.4 million for dry exploration well (Villmink) reflected as depreciation. Depreciation in Marine Geophysical, Onshore and Production decreased by $19.1 million, $6.8 million and $2.0 million, respectively. Depreciation in Marine Geophysical and Production generally decreased due to significant asset write-downs in 2003, partly offset by reduced depreciable life and reduced salvage value assumptions for FPSOs and seismic vessels implemented effective November 1, 2003. Depreciation capitalized as part of the cost of multi-client library was reduced by $9.1 million to $4.0 million in 2004.

Amortization of multi-client data library increased by $17.7 million, or 11%, to $173.3 million in 2004. Amortization as a percentage of multi-client revenues was 66% in 2004 compared to 69% in 2003. Amortization for 2004 included an additional charge for minimum amortization of $7.8 million and additional amortization on certain individual surveys of $23.5 million to write these surveys down to fair value. Minimum amortization in 2003 amounted to $4.0 million.

Operating profit was $88.7 million in 2004 compared to a loss of $645.3 million in 2003. In 2003 the Company recorded impairments and other operating (income) expense of $819.0 million.

Interest expense was $111.2 million in 2004 compared to $115.5 million in 2003. Average interest bearing debt was significantly lower in 2004 compared to 2003, but in 2003 most of the debt did not accrue interest for approximately three months while the Company was in Chapter 11 proceedings. Other financial items amounted to a loss of $11.2 million in 2004 compared to a loss of $27.2 million in 2003. The 2003 amount includes write off of $13.2 million of deferred debt costs and original issue discounts.

– Operating profit was $88.7 million in 2004 compared to a loss of $645.3 million in 2003

(1) Adjusted EBITDA, when used by the Company means net income (loss) before financial items, other gain (loss), taxes, depreciation and amortization, other (income) expense, impairment of long-term assets and discontinued operations. See financial statements (Note 34) for a reconciliation of Adjusted EBITDA to Net Income (Loss). Adjusted EBITDA may not be comparable to other similarly titled measures from other companies. We have included Adjusted EBITDA as a supplemental disclosure because the Company believes that it provides useful information regarding PGS' ability to service debt and to fund capital expenditures and provides investors with a helpful measure for comparing our operating performance with that of other companies.

Provision for income taxes was $28.6 million in 2004 compared to $26.4 million in 2003. Tax expense primarily relates to withholding taxes, taxes payable in regions where the Company has no carry-forward losses and to deferred taxes for Pertra, which is subject to petroleum taxation rules in Norway with a nominal tax rate of 78%. Under these taxation rules it is not possible to offset Pertra's income against tax losses from other operations.

Net loss for 2004 was $53.9 million compared to a net loss of $819.1 million in 2003.

Cash flow, balance sheet and financing

Net cash provided from operating activities amounted to $281.6 million in 2004 compared to $220.1 million in 2003. The 2004 amount includes payment of restructuring cost and other operating expense of $16.9 million compared to $71.1 million in 2003.

Cash and cash equivalents (excluding restricted cash) amounted to $132.9 million at December 31, 2004 compared $105.2 million at December 31, 2003. Restricted cash amounted to $35.5 million at December 31, 2004 compared to $51.1 million at December 31, 2003.

The Company has a $110 million two-year secured working capital facility (maturing March 2006), $70 million of which can be borrowed and used for general corporate purposes. The remaining $40 million is available for issuance of letters of credit to support bid and performance bonds associated with PGS' day-to-day operations. At December 31, 2004, approximately $15 million of letters of credit were outstanding under this facility. No amounts were outstanding under the revolving credit portion of the facility. Further, the Company in February 2005 established an additional overdraft facility of NOK 50 million as part of its Norwegian cash pooling system.

The nominal value of interest bearing debt, including capital leases, was approximately $1,164 million as of December 31, 2004 compared to $1,204 million at December 31, 2003.

The Company's interest bearing debt consisted of the following primary components at December 31, 2004:

10% Senior Notes, due 2010	$ 746 million
8% Senior Notes, due 2006	250 million
8.28% First Preferred Mortgage Notes, due 2011	99 million
Other loans, due 2005 – 2006	10 million
Total debt	$ 1 105 million
Capital leases	59 million
Total	$ 1 164 million

Net interest bearing debt (interest bearing debt, including capital leases, less cash and cash equivalents and restricted cash) was approximately $995 million as of December 31, 2004 compared to $1,071 million (adjusted for the final excess cash distribution of $22.7 million which was included in accrued expenses) at December 31, 2003.

The Company expects to use a portion of its cash position and proceeds from sale of Pertra to reduce debt during 2005. In March 2005, the Company called $175 million of its $250 million 8% Senior Notes, due 2006, for repayment in April at a price of 102% of par. The remaining balance is callable at 101% of par starting November 2005.

Certain of the Company's loan and lease agreements and its 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. The Company has received waivers and amendments allowing it to provide Norwegian GAAP financial statements in lieu of U.S. GAAP financial statements until June 30, 2005.

In addition to customary representations and warranties, certain of the Company's debt agreements contain covenants restricting the Company from incurring debt unless certain coverage ratios are met and limiting Company financial indebtedness, excluding project debt, to $1.5 billion. These debt agreements also restrict, among other things: payment of dividends; ability to place liens on Company assets; the amount of subsidiary financial indebtedness; sale/leaseback transactions; investments in project companies; investment in multi-client library; and asset dispositions. Specifically, certain financing agreements do not allow the Company to pay dividends or make any similar distribution until the $250 million 8% Senior Notes, due 2006, are repaid.

– The Company expects to use a portion of its cash position and proceeds from sale of Pertra to reduce debt during 2005

As required by Section 3-3 of the Norwegian Accounting Act, we confirm that the financial statements are prepared on the assumption of a going concern.

Financial risk description

Financial market risk

PGS is exposed to certain financial market risks, mainly adverse changes in interest rates and foreign currency exchange rates.

PGS conducts business in various currencies and is subject to foreign currency exchange rate risk on cash flows related to revenues, expenses, financing and investing transactions in currencies other than the U.S. dollar. Our cash flows from operations are primarily denominated in U.S. dollars, British pounds and Norwegian kroner. Our revenues are predominantly denominated in U.S. dollars while some portion of our operating expenses are incurred in British pounds and Norwegian kroner. Substantially all of our debt is denominated in U.S. dollars. Although we periodically undertake limited hedging activities to reduce certain currency fluctuation risks, these activities provide only limited protection against currency-related losses. As of December 31, 2004, we did not have any open derivative forward exchange contracts to manage the exposure related to these risks.

Our exposure to changes in interest rates relates primarily to our capital lease obligations and from our UK leases. As of December 31, 2004, we had capital lease obligations of approximately $59 million payable through 2008. Interest associated with these capital lease obligations is based on U.S. dollar LIBOR plus a margin.

PGS has entered into certain UK leases. 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. Actual interest rates have been lower than the assumed interest rates during the past several years.

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, 2004, we had one open interest rate swap agreement in the aggregate notional amount of $10.3 million which does not qualify for hedge accounting. The market value of this agreement was approximately $(0.5) million.

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. We manage our exposure to credit risk through ongoing credit evaluations of customers. Further, we believe that our exposure to credit risk is relative low due to the nature of our customer base, the long term relationship we have with most of our customers and the historic low level of losses on trade receivables.

Liquidity risk

As described above, at year end PGS had a cash balance of $132.9 million and a $110 million two-year secured working capital facility (maturing March 2006). In 2005, the Company established an additional overdraft facility of NOK 50 million and received approximately $155 million from the sale of Pertra.

Based on the year-end cash balance, available liquidity resources and the current structure and terms of PGS' debt, we believe that PGS has adequate liquidity and that liquidity risk is at acceptable levels.

Investments

During 2004, PGS had a total cash investment of $42.2 million in multi-client data library compared to $91.5 million in 2003, a reduction of $49.3 million, or 54%, reflecting the Company's continued focus towards the contract market.

Capital expenditures amounted to $148.4 million in 2004 compared to $57.7 million in 2003, an increase of $90.7 million. The increase relates in large part to Pertra capital expenditures (mainly drilling program), which increased $50.8 million to $85.0 million in 2004. Capital expenditures in Marine Geophysical increased $40.9 million to $56.9 million in 2004. This increase relates primarily to the Company's streamer replacement program, increased investments in data processing equipment and normal equipment replacement after unusually low investment levels during 2003.

Shares, share capital and dividend

As of December 31, 2004, PGS had 20 000 000 authorized shares issued and outstanding, all of

> – Further strengthening of financial flexibility is a key priority of the Company.

which are of the same class and with equal voting and dividend rights. Each share has a par value of NOK 30.

The Company's shares are listed on the Oslo Stock Exchange. The Company's American Depositary Shares ("ADSs") are listed on the NYSE.

Further strengthening of financial flexibility is a key priority of the Company. Consequently the Company expects to use its cash flow generation to develop its core businesses and maintain or improve financial ratios. The Company does therefore not expect to pay ordinary dividends to shareholders in the next two to three years. The Company is not allowed to pay dividends under its loan agreements until the $250 million 8% senior notes, due 2006, are repaid. At year-end 2004, the parent company does not have free equity that, under Norwegian corporate law, can be distributed as dividends.

U.S. GAAP reporting, restatements and internal control related matters

U.S. GAAP reporting

The Company filed its Annual Report on Form 20-F for the year ended December 31, 2003, including audited financial statements under U.S. GAAP for the years 2003, 2002 and 2001 on November 16, 2004. PGS restated previously published U.S. GAAP audited consolidated financial statements for the year ended December 31, 2001.

PGS' primary financial reporting is U.S. GAAP. Since fourth quarter 2003 the Company did not have a basis to issue U.S. GAAP financial statements until the 2002 and 2003 audits and 2001 re-audit of the Company's U.S. GAAP financial statements were completed. These audited financial statements are now completed, and the Company intends to commence reporting its quarterly financial statements on a U.S. GAAP basis effective first quarter 2005.

Effective January 1, 2005 publicly traded companies in EU and EEA countries are required to report financial statements based on International Financial Reporting Standards ("IFRS"). Several EU/EEA countries, including Norway, have established transition rules allowing companies that are listed for public trading in the U.S., and therefore, have prepared complete financial statements under U.S. GAAP, at least from and including 2002, to defer adopting IFRS reporting until January 1, 2007. Based on its listing and reporting history, PGS has concluded that the transition rules apply to the Company and intends to defer its IFRS reporting until January 1, 2007.

Restatements

The Company's Norwegian GAAP audited financial statements for 2003 were issued with a qualification that adjustments could arise from the results of the audit of the Company's financial statements under U.S. GAAP for 2003 and 2002 and the re-audit of the Company's U.S. GAAP financial statements for 2001. Upon completion of these audits the Company concluded that its historical treatment of interest-rate contingencies related to its UK leases should be restated under Norwegian GAAP. This restatement reduced retained earnings as of January 1, 2002 by $14.1 million. In addition, the restatement increased other financial items for the years ended December 31, 2002 and 2003 by $0.6 million and $0.9 million, respectively.

Material Weaknesses

PGS has previously disclosed material weaknesses in its internal controls over financial reporting. PGS has taken extensive actions to address the material weaknesses and has developed and is continuing to implement a plan to remediate those weaknesses. While the actions the Company has taken have significantly improved the quality of its internal controls over financial reporting, the Company has not eliminated all material weaknesses that were previously identified. PGS is committed to remediating the material weaknesses and deficiencies in internal controls over financial reporting as expeditiously as possible.

Health, Safety and Environment ("HSE")

HSE management and reporting is a key element in PGS' evaluation of business performance for all management levels and the Board of Directors.

Geophysical operations offshore and on land, as well as oil production offshore raise several environmental issues. To meet the continuously changing customer and industry expectations, investments have been made to further develop our HSE systems and competence. PGS places considerable emphasis on prevention and reduction of negative environmental impact of our operations worldwide. We apply a structured approach to ensure that our HSE responsibilities are well managed, and we strive for continuous improvement.

2004 was a good year with strong HSE performance. PGS' safety and environment results compare favorably with the norm in the industries in which we operate. Our HSE results effectively support our efforts to develop and maintain our position as a market leader in both geophysical and harsh environment floating production services.

Marine Geophysical has in 2004 implemented a

– 2004 was a good year with strong HSE performance.

new Environmental Management Manual in line with the ISO 14000 requirements and expectations.

HSE achievements in 2004 include:

- *Petrojarl Varg* ranked as one of the three safest offshore installations on the NCS by The Norwegian Petroleum Safety Authority (PSA)
- First year ever without lost time incidents in Production
- Implemented best available technology (BAT) to reduce discharges to sea within our seismic operations
- Production was ISO 14000 (international standard for environmental management) certified in 2004.
- Production (shuttle tankers) was certified by International Ships and Port Security Code (ISPS)
- Pertra headed up the oil industry's annual full scale oil contingency exercise in cooperation with NOFO (Norwegian Clean Seas Association for Operators) with great success.

PGS had a total of 9 lost time incidents in 2004, none which were of a serious nature. 2004 was the first year ever with no lost time incidents on any of Production's four FPSOs.

Overall, lost time incident frequency was 0.4 per million man hours in 2004, compared with a frequency of 0.33 for 2003 and 0.66 for 2002. The total recordable case frequency was 2.3 per million man hours in 2004 compared to 2.9 in 2003. Sick leave in our Norwegian operations was 4.5% in 2004 compared to 4.6% in 2003.

In 2004 Pertra caused 3,000 liters of oil to be discharged to sea. The incident was caused by a fatigue in a flexible production riser on the Varg field. The incident did not cause any major damage to the environment or wild life at sea. Further, the Company had in March 2004 a minor gas explosion onboard the *Petrojarl Varg*. The incident did not cause any harm to people, the environment or our assets. The incidents were reported in accordance with the regulations relating to material and information in the petroleum activities, section 11.

Organization

Employees by business area are specified as follows:

At December 31

Business area:	**2004**	2003	2002
Marine Geophysical	**1 115**	1 143	1 356
Onshore	**1 011**	1 479	1 828
Production	**501**	515	520
Pertra	**16**	5	6
Global Services/Reservoir/Corporate	**256**	235	252
Discontinued operations	**---**	---	41
Total	**2 899**	3 377	4 003

The nature of PGS' operations requires a high degree of technological expertise among its personnel. Traditionally a high proportion of its employees have been male. The Company strives for balance and equality with respect to sex, age and cultural background, and considers this as a main element of its core values. At December 31, 2004, 11% of the Company's employees were female and 89% male, while the allocation for PGS' Norwegian employees was 20% female and 80% male. University educated males and females (geophysicists, geologist, engineers etc) in PGS have the same wage structure. However, most females working in PGS are employed in functions, which traditionally are paid less. About 25 percent of this group is employed in 80 percent or less of a full time position for a shorter or longer period by own choice, primarily related to responsibility for small children. In management positions at PGS' headquarters at Lysaker, 26 percent are female and 74 percents are male. PGS' Board of Directors has 6 male and 1 female permanent directors.

The Company's head office is at Lysaker, Norway. PGS also has offices in other cities in Norway, and in the U.S., Angola, Australia, Brazil, China, Egypt, England, Mexico, Nigeria, Russia, Singapore, Scotland, the United Arab Emirates and Venezuela.

– The Company strives for balance and equality with respect to sex, age and cultural background, and considers this as a main element of its core values

Board of Directors and Corporate Governance

In 2004 the Board of Directors consisted of Jens Ulltveit-Moe (Chairman), Keith Henry (Alternate chairman), Francis Gugen, Harald Norvik, Rolf Erik Rolfsen, Clare Spottiswoode and Anthony Tripodo, all elected as permanent directors for a two-year period at the Extraordinary General Meeting held on October 16, 2003. Alternate directors are Marianne Elisabeth Johnsen and John Reynolds.

As part of the 2003 financial restructuring, the Extraordinary General Meeting resolved that Board decisions on certain specified major transactions, during the first two years after the completion of the restructuring, shall require the support by the board members nominated by the pre-restructuring shareholders (Messrs. Ulltveit-Moe, Norvik and Rolfsen) or their successors, and that until October 16, 2005, any election of new directors shall require the approval by more than two thirds of the votes cast as well as of the share capital which is represented at the General Meeting.

The Board has established two sub-committees, the Audit Committee, consisting of Messrs. Gugen (Chairman), Tripodo and Norvik, and the Remuneration Committee, consisting of Messrs. Henry and Rolfsen, to act as preparatory bodies for the Board of Directors and to assist the directors in exercising their responsibilities.

In 2004 the Board of Directors had 17 meetings.

PGS is committed to maintaining high standards of corporate governance. We believe that effective corporate governance is essential to the well being of the Company and establishes the framework by which we conduct ourselves in delivering services to our customers and value to our shareholders.

PGS is registered in Norway as a public limited company and the Company's governance model is built on Norwegian corporate law. PGS also adheres to requirements applicable to foreign registrants in the U.S., where the Company's ADSs are publicly traded, including the New York Stock Exchange listing standards. The Company otherwise implements corporate governance guidelines beneficial to its business.

PGS' corporate governance principles are adopted by the Board of Directors. The Board conducts a periodic review of these principles. Key aspects of the Company's corporate governance structure are described in more detail in the separate corporate governance report in the 2004 annual report. PGS ASA's articles of association, in addition to full versions of the rules of procedures for the Board of Directors, the Audit Committee charter, the Remuneration Committee charter and the code of conduct are available on the Company's website (www.pgs.com).

Outlook

The markets in which PGS operates showed improvement in 2004. Oil prices varied significantly through 2004, but generally at relatively high levels. Development so far in 2005 is favorable. Market analysts generally expect a high price level to continue. In the medium to long term, high price levels would positively impact PGS' core markets.

Over the past few years, E&P companies have made relatively low investments in exploration, and there is arguably still under-investment in oil exploration, despite increased activity in 2004. There are signs that the oil companies will be gradually more active in exploration during the coming years, as reserves replacement becomes even more critical.

After a number of years of overcapacity, the marine seismic market balance has improved, as reflected in increased industry order backlog and margins. Within floating production, increased focus on smaller fields and tail-end optimization forms a basis for growth in outsourcing where PGS Production is well positioned with market leadership in the North Sea and the potential to grow in selected international markets.

In 2005, PGS will operate from a more focused oil services base seeking to further build its competitive advantage and market leading position. At the same time, PGS will continue to manage its business in a financially disciplined manner – focusing on improvement in return on capital employed, cash generation and prudent risk management.

In 2005, we expect the following factors to influence performance:

Marine Geophysical

- Increased contract prices as a 3D market near full capacity utilization is expected during 2005
- Multi-client late sales lower than 2004 due to limited reinvestment over the past three years and expected delay of Brazilian 7th Licensing Round sales into 2006
- Cost levels impacted by increased fuel prices and weaker U.S. dollar compared to 2004

Onshore

- Continued focused approach centered around markets where PGS can compete most effectively
- Full year activity level at par with 2004, building on expected start-up of significant transition zone project in Nigeria and contract awards for South America crews

– After a number of years of overcapacity, the marine seismic market balance has improved, as reflected in increased industry order backlog and margins

Production

- The Company's FPSOs are all expected to continue producing on existing assignments through 2006
- Total oil production from the four FPSOs taken together is expected to be in line with 2004
- Increased maintenance cost as the time since deployment of all FPSOs on their respective fields is increasing. In addition USD currency has depreciated compared to 2004

The Board emphasizes that forward looking statements contained in this report are based on various assumptions made by the Company that are beyond its control and that are subject to certain risks and uncertainties as disclosed by the Company in its filings with the Oslo Stock Exchange and the U.S. Securities and Exchange Commission. Accordingly, actual results may differ materially from those contained in the forward looking statements.

Settlement of the parent company's loss for 2004

The parent company, Petroleum Geo-Services ASA, reported a net loss of NOK 824,248,000 for 2004. The Board of Directors proposes that the loss is covered by transfer from additional paid in capital.

At December 31, 2004, the parent company had no free equity that, under Norwegian corporate law, can be distributed as dividends.

March 31, 2005

Jens Ulltveit-Moe *Chairman*	Clare Spottiswoode	Harald Norvik	Anthony Tripodo
Keith Henry *Vice chairman*	Rolf Erik Rolfsen	Francis Gugen	Svein Rennemo *Chief Executive Officeer*

Petroleum Geo-Services

Consolidated Statements of Operations

(In thousands of dollars)	Note	Years ended December 31, 2004	2003	2002
Revenue	4	**$ 1 135 461**	$ 1 120 658	$ 992 336
Cost of sales/ -products		**639 251**	584 717	473 877
Depreciation and amortization	4	**326 996**	305 419	356 427
Research and development costs		**3 419**	2 622	2 766
Selling, general and administrative costs		**65 314**	54 251	55 235
Impairment of long-lived assets	4, 32	**-**	740 876	807 416
Other operating expense, net	4, 32	**11 760**	78 085	15 434
Total operating expenses		**1 046 740**	1 765 970	1 711 155
Operating profit (loss)	4	**88 721**	(645 312)	(718 819)
Income (loss) from associated companies	5	**5 277**	897	(1 691)
Interest expense	6	**(111 233)**	(115 459)	(151 252)
Other financial items, net	7	**(11 182)**	(27 181)	42 803
Income (loss) before income taxes		**(28 417)**	(787 055)	(828 959)
Income tax expense	8	**28 558**	26 436	201 944
Income (loss) from continuing operations		**(56 975)**	(813 491)	(1 030 903)
Income (loss) from discontinued operations, net of tax	3	**3 048**	(5 587)	(215 349)
Net income (loss)		**$ (53 927)**	$ (819 078)	$ (1 246 252)
Hereof minority interest		**$ 350**	$ 125	$ -
Hereof majority interest	9	**$ (54 277)**	$ (819 203)	$ (1 246 252)

March 31, 2005

Jens Ulltveit-Moe
Chairman

Clare Spottiswoode

Harald Norvik

Anthony Tripodo

Keith Henry
Vice chairman

Rolf Erik Rolfsen

Francis Gugen

Svein Rennemo
Chief Executive Officeer

Petroleum Geo-Services

Consolidated Balance Sheets

(In thousands of dollars)	Note	December 31, 2004	December 31, 2003
ASSETS			
Long-term assets:			
Long-lived intangible assets	12	**$ 2 075**	$ 1 975
Property and equipment, net	14	**1 042 279**	1 089 098
Multi-client library, net	15	**240 596**	367 700
Oil and natural gas assets, net	16	**63 956**	30 678
Restricted cash	20	**10 014**	10 014
Investments in associated companies	4, 5	**5 720**	6 386
Other financial assets	17	**40 105**	29 523
Total long-term assets		**1 404 745**	1 535 374
Current assets:			
Accounts receivable, net	18	**201 844**	172 508
Other current assets	19	**70 195**	64 737
Restricted cash	20	**25 477**	41 123
Cash and cash equivalents		**132 942**	105 225
Total current assets		**430 458**	383 593
Total assets	4	**$ 1 835 203**	$ 1 918 967
LIABILITIES AND SHAREHOLDERS' EQUITY			
Shareholders' equity:			
Paid in capital:			
Common stock (20 000 000 shares, par value NOK 30)		**$ 85 714**	$ 85 714
Additional paid in capital		**287 576**	287 576
Total paid in capital		**373 290**	373 290
Other equity		**(70 436)**	(20 118)
Minority interest		**1 226**	1 527
Total shareholders' equity		**304 080**	354 699
Debt:			
Accruals for long-term liabilities:			
Deferred tax liabilities	8	**28 445**	4 253
Other long-term liabilities	23	**133 342**	114 015
Total accruals for long-term liabilities		**161 787**	118 268
Other long-term debt:			
Long-term capital lease obligations	10	**33 156**	61 234
Long-term debt	25	**1 085 190**	1 108 675
Total other long-term debt		**1 118 346**	1 169 909
Current liabilities:			
Short-term debt and current portion of long-term debt and capital lease obligations	10, 24, 25	**45 373**	34 487
Accounts payable		**81 910**	56 318
Accrued expenses	26	**115 448**	157 143
Income taxes payable	8	**8 259**	28 143
Total current liabilities		**250 990**	276 091
Total liabilities and shareholders' equity		**$ 1 835 203**	$ 1 918 967

Petroleum Geo-Services

Consolidated Statements of Cash Flows

(In thousands of dollars)	Years ended December 31, **2004**	2003	2002
Cash flows from operating activities:			
Net income (loss)	**$ (54 277)**	$ (819 203)	$ (1 246 252)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization charged to expense	**326 996**	305 419	356 427
Non-cash impairments and loss (gain) on sale of subsidiaries	**-**	745 697	1 039 472
Non-cash write-off of deferred debt costs and issue discounts	**-**	13 152	-
Cash effects related to discontinued operations	**-**	3 342	5 540
Provision (benefit) for deferred income taxes	**26 970**	(4 639)	184 577
Changes in current assets, current liabilities and other	**(37 881)**	(9 988)	(16 625)
Loss on sale of assets	**4 128**	6 193	7 561
Net (increase) decrease in restricted cash	**15 646**	(19 904)	1 602
Net cash provided by operating activities	**281 582**	220 069	332 302
Cash flows (used in) provided by investing activities:			
Investment in multi-client library	**(42 159)**	(91 500)	(190 436)
Capital expenditures	**(148 372)**	(57 710)	(60 759)
Capital expenditures on discontinued operations	**-**	(118)	(77 364)
Sale of subsidiaries	**2 035**	50 115	20 222
Other items, net	**4 031**	3 835	(9 030)
Net cash used in investing activities	**(184 465)**	(95 378)	(317 367)
Cash flows (used in) provided by financing activities:			
Redemption of preferred stock	**-**	(64 105)	(98 983)
Repayment of long-term debt	**(24 167)**	(11 241)	(241 826)
Principal payments under capital leases	**(21 121)**	(17 539)	(15 496)
Net increase (decrease) in bank facility and short-term debt	**1 962**	(48)	335 348
Net (payments) receipts under tax equalization swap contracts	**-**	-	9 566
Distribution to creditors under the restructuring agreement	**(22 660)**	(17 932)	-
Other items, net	**(3 488)**	-	8 098
Net cash used in financing activities	**(69 474)**	(110 865)	(3 293)
Effect of exchange rate changes on cash	**74**	14	537
Net increase (decrease) in cash and cash equivalents	**27 717**	13 840	12 179
Cash and cash equivalents at beginning of year	**105 225**	91 385	79 206
Cash and cash equivalents at end of year	**$ 132 942**	$ 105 225	$ 91 385

Petroleum Geo-Services

Consolidated Statements of Changes in Shareholders' Equity

(In thousands of dollars, except for share data)	Common Stock Number	Common Stock Par value	Additional paid-in capital	Accumulated foreign currency translation adjustments	Other equity	Minority interest	Share-holders' equity
Balance at December 31, 2002	102 347 987	$ 71 807	$ -	$ (6 638)	$ (107 339)	$ 1 402	$ (40 768)
Restated for prior year net income effect:							
UK leases	-	-	-	-	(14 619)	-	(14 619)
Restated balance at December 31, 2002	102 347 987	71 807	-	(6 638)	(121 958)	1 402	(55 387)
Cumulative effect of accounting principle change January 1, 2003	-	-	-	-	(26 754)	-	(26 754)
Effect of restructuring, November 6, 2003:							
Write down old sharecapital	(102 347 987)	(71 807)	-	-	71 807	-	-
Debt restructuring	20 000 000	85 714	1 010 989	-	157 148	-	1 253 851
Net income	-	-	(723 413)	-	(95 790)	125	(819 078)
Translation adjustments	-	-	-	2 067	-	-	2 067
Balance at December 31, 2003	20 000 000	85 714	287 576	(4 571)	(15 547)	1 527	354 699
Net income	-	-	-	-	(54 277)	350	(53 927)
Dividens to minority interest	-	-	-	-	(264)	-	(264)
Revaluations (of shares available for sale)	-	-	-	-	5 889	-	5 889
Translation adjustments & other	-	-	-	(1 666)	-	(651)	(2 317)
Balance at December 31, 2004	**20 000 000**	**$ 85 714**	**$ 287 576**	**$ (6 237)**	**$ (64 199)**	**$ 1 226**	**$ 304 080**

Petroleum Geo-Services ASA has one class of shares, and as of December 31, 2004, common stock consisted of a total of 20 000 000 shares of par value NOK 30 each fully paid in.

During 2003, the Company completed an extensive financial restructuring (see Note 25 for more information). Besides a significant reduction of the Company's total debt, the restructuring lead to a cancellation of all existing shares, and the share capital was reduced to zero without any payment to the existing shareholders in respect of the cancelled shares. Simultaneously with the registration of the reduction of the share capital to zero, the reorganized Petroleum Geo-Services ASA issued 20 000 000 new shares with a par value of NOK 30 per share, giving a total share capital of NOK 600 million. The new shares were distributed to the Company's creditors and existing shareholders.

The shareholders voting rights are equal to ownership percentage. A listing of the Company's largest shareholders is provided in Note 21.

Notes to the Consolidated Financial Statements

Note 1 General Information About the Company and Basis of Presentation

General:

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

PGS is a technologically focused oilfield service company principally involved in providing geophysical services worldwide and floating production services in the North Sea. Globally, 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. Through 2004, the Company also owned a small oil and natural gas company that produces oil and natural gas from licences on the Norwegian Continental Shelf. This investment was divested in March 2005. The Company's headquarters are at Lysaker, Norway. See further discussion of the Company's services in Note 4.

The Company has prepared its consolidated financial statements in accordance with accounting principles generally accepted in Norway ("N GAAP"). The Financial Statements are presented in US Dollars ("$"), which is defined as the reporting currency.

As more fully described in Note 3, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. in December 2003. The Company sold its Production Services subsidiary in December 2002 and its Atlantis subsidiary in January 2003, which was finalized and executed in February 2003. Accordingly, the financial position and results of operations and cash flows for these subsidiaries have been presented as discontinued operations as of and for the years ended December 31, 2003 and 2002.

The accompanying financial statements have been prepared on the basis of accounting principles that presume the realization of assets and the settlement of liabilities in the ordinary course of business. Accordingly, the financial statements do not purport to present the realizable values of all assets or the settlement amounts of all liabilities, and therefore, do not reflect the adjustments in the carrying values of our assets, liabilities, income statement items and balance sheet classifications that would be necessary if the going concern assumption was not an appropriate basis for our financial statements.

In 2003 the Company, as more fully described in Note 25, successfully completed a financial restructuring which involved cancellation of all pre-restructuring share capital and a reduction of interest bearing debt of $1,283 million from $2,472 million to $1,189 million. Costs relating to this restructuring totalled $3.5 million and $42.3 for the years ended December 31, 2004 and 2003, respectively and were expensed as other operating expense, net in the consolidated statements of operations. In addition the Company recorded $13.2 million in write-off of deferred debt costs and issue discounts, that were expensed as other financial items, net.

Upon emergence from Chapter 11, the Company, for the purpose of adopting "fresh start" reporting in accordance with "The American Institute of Certified Public Accountants Statement of Position" (SOP 90-7) under generally accepted accounting principles in the United States ("U.S. GAAP") and in order to perform impairment reviews for its N GAAP financial statements, made a full valuation, using external experts, of all its significant assets and liabilities, with a basis in the restructured enterprise value. Similarly the Company adopted a new N GAAP standard for Impairment of Assets effective January 1, 2003. In total the Company recognized the following impairments under N GAAP in 2003; $241.5 million in multi-client library, $367.0 million in Production assets, $129.1 million in streamer fleet assets and $3.3 million in other long-term assets. See Note 32 for further details of these impairments.

Restatements:

The Company filed its Annual Report on Form 20-F for the year ended December 31, 2003, including audited financial statements under U.S. GAAP for the years ended December 31, 2003, 2002 and 2001 on November 16, 2004. In connection with finalizing the audited financial statements in accordance with U.S. GAAP, PGS restated previously published U.S. GAAP audited consolidated financial statements for the year ended December 31, 2001.

The previously issued Norwegian GAAP audited financial statements for 2003 were issued subject to adjustments that could arise from the results of the audit of the Company's financial statements under U.S. GAAP for 2003 and 2002 and the re-audit of the Company's U.S. GAAP financial statements for 2001. Upon completion of these audits the Company has concluded that its historical treatment of interest-rate contingencies related to its UK leases should also be restated under Norwegian GAAP.

In previously issued financial statements, all gains associated with UK lease transactions were recognized as and when associated tax contingencies were considered remote. However, a portion of these gains should have been deferred for liabilities related to the difference, at inception of the lease, between the projected future distribution from the Payment Banks and the projected lease payments, based on forward interest rate curves (see Note 2). This deferred gain should have been amortized over the term of the lease. The restatement reduced retained earnings as of January 1, 2002 by $14.1 million. Furthermore, the restatement increased other financial items for the year ended December 31, 2002 and 2003 by $0.6 million and $0.9 million, respectively.

Further, as a reflection of conclusions reached in connection with the finalization of the U.S. GAAP financial statements for the years 2003, 2002 and 2001, the Company has incorporated certain changes in the presentation and classification of transactions in its Norwegian GAAP financial statements. Such changes include separate balance sheet presentation of restricted cash and reclassification of two leases from operating leases to capital leases.

When completing the 2003 N GAAP financial statements, the Company identified certain costs which historically had not been accrued appropriately relating to seismic vessels costs of $2.9 million, vessel crew rotation costs of $4.0 million and accrued vacation costs, relating to certain regions in the Company, of $3.7 million. The effect of these accruals were recorded directly to shareholders' equity in the year ended December 31, 2002.

Material Weaknesses:

PGS has previously disclosed material weaknesses in its internal controls over financial reporting. PGS has taken extensive action to address the material weaknesses and has developed and is continuing to implement a plan to remediate those weaknesses. While the actions the Company has taken have significantly improved the quality of its internal controls over financial reporting, the Company has not eliminated all material weaknesses that were previously identified. PGS is committed to remediating the material weaknesses and deficiencies in internal controls over financial reporting as expeditiously as possible.

U.S. GAAP Reporting and International Financial Reporting Standards ("IFRS"):

PGS' primary financial reporting is U.S. GAAP. Effective January 1, 2005 publicly traded companies in EU and EEA countries are required to report financial statements based on IFRS. Several EU/EEA countries, including Norway, have established transition rules allowing companies that are listed for public trading in the U.S., and therefore, have prepared complete financial statements under U.S. GAAP, at least from and including 2002, to defer adopting IFRS reporting until January 1, 2007. Based on its listing and reporting history, PGS has concluded that the transition rules apply to the Company and plans to defer IFRS reporting until January 1, 2007.

Note 2 Summary of Significant Accounting Policies

Use of Estimates:

The preparation of financial statements in accordance with N 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's consolidated financial statements include all transactions of Petroleum Geo-Services ASA, its wholly owned and majority-owned subsidiaries that it controls. Subsidiaries are consolidated in the accounts from the point of time when the Company gains control. Shares in subsidiaries are eliminated using the purchase method of accounting. This implies that the purchase costs for the shares are assigned to the assets and liabilities of the subsidiaries, using their fair value at the date of acquisition. Any excess is recorded as goodwill. 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. The equity method implies that the Company's share of net income in the associated company is included in a separate line in the profit and loss statement, while the Company's share of the associated company's equity, adjusted for any excess values or goodwill, is classified as a long-term asset in the balance sheet.

Shares available for sale with an available market value are carried at fair value at each balance sheet date, with unrealised gains recorded directly to equity. Gains are recognized in the statement of operations when realized.

Discontinued Operations:

Subsidiaries that are either held-for-sale or discontinued are reported as discontinued operations. Revenues and expenses are excluded from revenue and expenses of the Company and reported separately as a one line item in the consolidated statement of operations, net of tax. Assets and liabilities are presented as separate line items in the balance sheet. For further details, see discussions of such discontinued activities in Note 3.

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 deposits 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.

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 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 Company's exchange rate between the Norwegian Kroner and US dollar at December 31, 2004 and 2003 was NOK 6.13 and NOK 6.79, respectively.

Operating and Capital Leases:

The Company has significant operating lease arrangements within all the operating segments and also has some capital lease arrangements mainly for land seismic equipment. Capital leases are lease arrangements where the substantial financial risk and control, but not ownership, of the assets are transferred from the lessor to the Company.

The Company accounts for capital lease arrangements as if the Company had acquired the assets. Correspondingly the present value of the future lease payments is accounted for as liabilities. The assets are depreciated over the expected useful life of the asset, while the lease liability is reduced in accordance with the agreed payment term.

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 (see Note 10). Under the UK 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 or 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 theses 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. In previously issued financial statements, all gains associated with UK lease transactions were recognized as and when associated tax contingencies were considered remote. However, a portion of these gains should have been deferred for liabilities related to the difference, at inception of the lease, between the projected future distribution from the Payment Banks and the projected lease payments, based on forward interest rate curves. This deferred gain should have been amortized over the term of the lease. The financial statements for the years ended December 31, 2003 and 2002 have been restated to reflect this accounting (see Note 1 and 10).

The Defeased Rental Payments are based on assumed Sterling LIBOR rates of 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"). Such payments are made annually or bi-annually and are recorded as other financial items, net.

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.

Retirement Plans:

Defined benefit pension plans are estimated as present value of future pension compensation, which for accounting purpose are considered earned as of balance sheet date. Pension assets are estimated at fair value. Net pension liabilities on under-funded plans are recorded as other long-term liabilities, while net pension assets on over-funded plans are recorded as other long-term assets, if it is probable that the over-funded amounts can be utilized. Change in the pension liability, which is caused by amendments to the pension plans, is apportioned over the expected average remaining years of service.

The Company's contributions to defined contribution plans are expensed as incurred.

The actual pension costs are charged to salaries and social expenses and are included in cost of sales and selling, general and administration costs as appropriate, in the consolidated statements of operations.

Multi-Client Library:

The multi-client library consists of seismic 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.

Beginning January 2003, the Company no longer capitalizes the proportionate cost of relocating its crews (steaming) between surveys and the apportioned cost of yard stays.

The multi-client library is stated at the lower of survey costs less accumulated amortization or fair value. Fair value is calculated based upon remaining forecasted future sales less estimated selling costs, discounted to a net present value using discount rates that give effect to the inherent risk in the sales forecasts.

The Company records its investment in the multi-client library 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. Effective November 1, 2003, 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 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 the survey or group of surveys in relation to its 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 book value 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 of the multi-client library.

Effective November 1, 2003 the Company revised the minimum amortization period from eight years for marine surveys and five years for onshore surveys to five years for both marine and onshore projects from the end of the year of completion (the year when the project is completed and processed data is ready and available for use) and three years for derivative processed projects (processing or reprocessing that creates data that can be marketed and sold as an addition to the existing library) from the end of the year of completion. Existing marine surveys were accorded a transition profile that will generally shorten their remaining minimum amortization period by one year as compared to the previous profile.

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

Surveys completed in 2003 and prior years		
Calendar year of completion	Marine surveys	Land surveys
2003	80%	80%
2002	60%	60%
2001	40%	40%
2000	20%	20%
1999	10%	0%
1998	10%	
1997	0%	

New surveys		
Calendar year after completion	5-year Profile	3-year Profile
Year 1	80%	66%
Year 2	60%	33%
Year 3	40%	0%
Year 4	20%	
Year 5	0%	

In addition, effective January 1, 2004, the Company classifies write downs of individual multi-client surveys which are based on changes in project specific expectations and not individually material, as amortization expense. Such additional, non-sales related, amortisation expenses would be expected to appear regularly since projects are evaluated on an individual basis, except as described above. Write-downs related to fundamental changes in estimates affecting a larger part of the Company's multi-client library and which are material are classified as impairment in the consolidated statement of operations. Previously all write-downs of multi-client library were classified as impairment expense.

Research and Development costs:

Research and development costs are expensed as incurred.

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. Through the first ten months of 2003 the unit-of-production method of accounting was used for one of the FPSO vessels.

The estimated useful lives for the Company's property and equipment, as of December 31, 2004, were as follows:

	Years
Seismic vessels	20 – 25
Seismic and operations computer equipment	3 – 15
FPSO vessels and equipment	25 – 30
Buildings and related leasehold improvements	1 – 30
Fixture, furniture, fittings and office computers	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 its 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:

Effective January 1, 2003 the Company adopted 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. Reserves numbers are updated quarterly by the Company and verified at least annually by independent reservoir engineers. 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, discounted, 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.

Goodwill:

Goodwill represents the excess of the purchase price over fair value of the net assets acquired, and is stated at cost less accumulated amortization and any impairment charges. Goodwill amortization is based on an individual assessment and calculated on a straight-line basis over the estimated life.

Other Long-Lived Intangible Assets:

Other long-lived intangible assets generally relate to direct costs of software product development, patents, royalties and licenses. Other long-lived intangible assets are stated at cost less accumulated amortization and any impairment charges. Amortization is calculated on a straight-line basis over the estimated period of benefit, ranging from one to ten years.

Other Financial Assets:

Other financial assets consist of costs related to entering into long-term loan facilities (deferred debt issue costs) and long-term receivables. The Company defers debt issue costs relating to long-term debt, which is charged to expense using the *effective interest method* over the period loans are outstanding. Such expense is charged to interest expense. Long-term receivables includes accounts receivable expected to be collected more than twelve months after the balance sheet date (including government grants and contractual receivables related to asset removal obligations) and also net pension assets on over-funded plans.

Impairment of Long-Lived Assets:

Long-lived assets (multi-client library, property, plant & equipment and oil & gas assets) are assessed for possible impairment when indications of impairments exist. 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. In assessing impairment, 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. Value in use is computed based on discounted estimated future cash flows. Impaired assets are written down to their estimated recoverable amounts.

See further details on multi-client library above.

Loss Contracts:

The Company reviews its revenue-producing exclusive contracts in the ordinary course of business to determine if estimated costs to perform the contract exceed the estimated contract revenue. Any resulting net loss is expensed at the time the loss is determined.

Derivative Financial Instruments:

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 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, 2004, 2003 and 2002, the Company did not have outstanding any derivative financial instruments that qualified for hedge accounting.

Revenue Recognition:

The Company has elected to use the US Securities and Exchange Commission's Staff Accounting Bulletin (SAB) No. 104 Revenue Recognition as principle for recognising revenue. SAB-104 is considered to be in compliance with N GAAP for the principles applied. 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", which is also considered to be in accordance with N GAAP. 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. The Company's revenue recognition policy is described in more detail below.

1. Geophysical Services (Marin, Onshore and Other):

(a) Sales of Multi-Client Library Data:

Late sales – The Company grants a license to a customer, which entitles the customer to have access to a specifically defined portion of the multi-client data library. The customer's license payment is fixed and determinable, and typically is required at the time that the license is granted. The Company recognizes revenue for late sales when the customer executes a valid license agreement and has 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 the customer 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 instalment 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 project commences. In return for the pre-funding, the customer typically gains the ability to direct or influence the project specifications, to access data as it is being acquired and to pay discounted prices.

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

(b) Proprietary Sales/Contract Sales:

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

(c) Other Geophysical Services:

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

2. Production Services:

Tariff-based revenue from the 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. Revenue Products (Pertra):

Revenue from the Company's ownership of production licenses is recognized when ownership of produced oil passes to the customer (delivery).

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", which is also considered to be in accordance with N GAAP.

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 that is more likely than not to be recoverable. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. At acquisition, excess values are recorded as gross, including deferred tax, while goodwill is recognised net, excluding deferred tax accrual. The Company does not recognize any deferred tax liability on unremitted earnings of foreign subsidiaries when remittance is expected to be deferred indefinitely.

Asset Retirement Obligations:

The Company records 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 initially 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 estimated cash flows required to settle the ARO. The effect of such changes are recorded as cost of sales.

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 consolidated balance sheets under other financial assets.

Consolidated Statements of Cash Flows and Consolidated Statements of Operations:

The Company's consolidated statements of cash flows is prepared in accordance with the indirect method, where cash flows from operating activities are incorporated as a part of the cash flow statement, and where the cash flows are divided into operating activities, investing activities and financing activities. In order to provide the best possible reconciliation to our financial statements prepared in accordance with U.S. GAAP, the Company has decided to use Net Income (Loss) as the basis for presentation of cash flows from operating activities. Similarly, the consolidated statement of operations is presented on a format used under U.S. GAAP, where operating costs are classified as; cost of sales, research and development and selling, general and administration costs.

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.

Note 3 Acquisitions and Dispositions

In December 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. The Company received proceeds of $20.2 million at the closing date and received an additional $3.8 million in 2003 upon settlement of the working capital. Furthermore, the Company recorded additional gains of $3.0 million and $3.5 million relating to contingent events for the years ended December 31, 2004 and 2003, respectively. The Company is eligible to receive an additional $3.0 million upon the occurrence of certain contingent events through 2010.

In February 2003, the Company sold its Atlantis oil and gas activities to Sinochem, and received proceeds 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 $190.1 million in impairment charges, including the estimated loss on disposal. The Company recorded an additional $4.8 million in loss on disposal of this subsidiary in 2003.

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

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

	Years ended December 31,			
	2003	2002		
(In thousands of dollars)	Tigress	Tigress	Atlantis	Production
Revenue	1 244	1 684	23 452	181 302
Operating expenses before depreciation, amortization, impairment and other operating income and expenses	(2 697)	(3 298)	(15 836)	(176 642)
Depreciation and amortization	(707)	(1 105)	---	(455)
Impairment of long-term assets	---	---	(190 101)	---
Other operating income and expenses	(512)	(482)	---	---
Total operating expenses	(3 916)	(4 885)	(205 937)	(177 097)
Operating profit (loss)	(2 672)	(3 201)	(182 485)	4 205
Financial expenses and other financial items, net	(1 213)	(1 278)	1 545	(74)
Income (loss) before income taxes	(3 885)	(4 479)	(180 940)	4 131
Capital expenditures of discontinued operations	118	135	77 126	103

A reconciliation of income (loss) before income taxes, as reported above, and income (loss) from discontinued operations, net of tax, as presented in the consolidated statements of operations, is as follows:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Income (loss) before income taxes	---	(3 885)	(181 288)
Loss on disposal	---	(4 821)	(26 791)
Additional proceeds	3 048	3 500	---
Income tax benefit (expense)	---	(381)	(7 270)
Income (loss) from discontinued operations, net of tax	3 048	(5 587)	(215 349)

Operating expenses relating to discontinued operations includes corporate management fees based on actual charges to these entities. For continuing operations such fees are presented in the segment for Research/Shared Services/Corporate (see note 4).

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

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 (28%) and Norsk Hydro (42%). The Company's 30% partner is the Norwegian government's State Direct Financial Interest. The Company's FPSO vessel, *Petrojarl Varg*, has been in production on the Varg field of the license since December 1998.

Subsequent event:

On February 1, 2005, the Company signed an agreement to sell its wholly-owned subsidiary Pertra AS to Talisman, and the transaction was closed March 1, 2005. The sales price was approximately $155 million with a gain totalling approximately above $140 million, based on book-value of net assets of December 31, 2004. The Pertra operations up to March 1, 2005, will be presented as discontinued operations in the consolidated financial statements for 2005.

See note 4 for selected financial information for Pertra for the years ended December 31, 2004, 3003 and 2002. In addition income before income taxes for these years were $26.6 million, $31.7 million and $3.2 million and income tax expense were $27.6 million, $5.3 million and $4.7 million, respectively.

Note 4 Segment and Geographic Information

In 2004 we managed our 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 onshore multi-client library;
- Production, which owns and operates four harsh environment FPSOs in the North Sea; and
- Pertra, a small oil and natural gas company that owned 70% of and was operator for PL 038 on the Norwegian Continental Shelf ("NCS") and also had participating interest in six additional NCS licenses without current production.

Pertra was sold to Talisman in March 2005 and will be reported as discontinued operations in the 2005 financial statements.

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 (PL 038), which is 70% owned and operated by Pertra, is producing 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 Reservoir/Shared Services/Corporate. Significant charges, which do not relate to the operations of any segment, such as debt restructuring costs, are also presented as Reservoir/Shared Services/Corporate. Information related to discontinued operations during any period presented has been separately aggregated. Affiliated sales are made at prices that approximate market value. Interest and income tax expense is not included in the measure of segment performance.

Information by business segment is summarized as follows:

(In thousands of dollars)	Marine Geophysical	Onshore	Production	Pertra (a)	Reservoir/ Shared Services/ Corporate	Elimination	Total
Revenue, unaffiliated companies:							
2004	**565 307**	**133 162**	**237 815**	**186 717**	**12 460**	**---**	**1 135 461**
2003	582 687	154 034	248 310	121 641	13 986	---	1 120 658
2002	548 186	109 094	289 514	32 697	12 845	---	992 336
Revenue, including affiliates:							
2004	**574 214**	**133 162**	**298 202**	**186 717**	**20 852**	**(77 686)**	**1 135 461**
2003	584 180	154 034	293 415	121 641	21 200	(53 812)	1 120 658
2002	553 597	109 094	304 397	32 697	16 022	(23 471)	992 336
Depreciation and amortization: (e)							
2004	**199 487**	**36 685**	**39 794**	**47 791**	**3 239**	**---**	**326 996**
2003	195 397	38 023	41 783	24 788	5 428	---	305 419
2002	251 925	37 617	56 640	5 381	4 864	---	356 427
Other operating expenses: (b)							
2004	**365 191**	**98 216**	**173 486**	**108 272**	**38 912**	**(76 093)**	**707 984**
2003	335 802	99 164	164 672	60 784	34 980	(53 812)	641 590
2002	277 463	78 217	140 206	23 572	30 891	(18 471)	531 878
Adjusted EBITDA: (c)							
2004	**209 023**	**34 946**	**124 716**	**78 445**	**(18 060)**	**(1 593)**	**427 477**
2003	248 378	54 870	128 743	60 857	(13 780)	---	479 068
2002	276 134	30 877	164 191	9 125	(14 869)	(5 000)	460 458
Impairment of long-lived assets:							
2004	**---**	**---**	**---**	**---**	**---**	**---**	**---**
2003	359 834	11 822	367 021	---	2 199	---	740 876
2002	310 734	64 808	429 714	---	2 160	---	807 416
Other operating expense, net:							
2004	**(13)**	**9**	**---**	**---**	**11 764**	**---**	**11 760**
2003	22 908	304	---	---	54 873	---	78 085
2002	1 341	2 625	---	---	11 468	---	15 434
Operating profit (loss):							
2004	**9 549**	**(1 748)**	**84 922**	**30 654**	**(33 063)**	**(1 593)**	**88 721**
2003	(329 761)	4 721	(280 061)	36 069	(76 280)	---	(645 312)
2002	(287 866)	(74 173)	(322 163)	3 744	(33 361)	(5 000)	(718 819)
Loss from discontinued operations, net of tax:							
2004	**---**	**---**	**3 048**	**---**	**---**	**---**	**3 048**
2003	(4 298)	---	3 500	(4 789)	---	---	(5 587)
2002	(7 804)	---	(22 846)	(184 699)	---	---	(215 349)
Investment in associated companies:							
2004	**235**	**---**	**5 411**	**---**	**74**	**---**	**5 720**
2003	1 505	---	4 807	---	74	---	6 386
Total assets:							
2004	**773 485**	**89 205**	**721 907**	**113 639**	**136 967**	**---**	**1 835 203**
2003	883 184	113 345	769 944	60 897	91 597	---	1 918 967
Additions to long-lived tangible assets: (d)							
2004	**88 761**	**10 817**	**988**	**84 991**	**5 088**	**(114)**	**190 531**
2003	84 486	28 233	515	34 165	1 811	---	149 210
2002	198 780	32 061	8 238	10 913	1 203	---	251 195
Capital expenditures on discontinued operations:							
2004	**---**	**---**	**---**	**---**	**---**	**---**	**---**
2003	118	---	---	---	---	---	118
2002	135	---	103	77 126	---	---	77 364

(a) 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) Other operating expenses consist of cost of sales/-products, research and development costs, and selling, general and administrative costs.

(c) See Note 34 for further definition of Adjusted EBITDA and a full reconciliation of Adjusted EBITDA from Net Income (Loss).

(d) Consist of cash investment in multi-client library and capital expenditures.

(e) Includes costs associated with dry wells for 2004 (Pertra).

Since the Company provides services worldwide to the oil and natural gas industry, a substantial portion of the property and equipment is mobile, and the respective locations at the end of the period (as listed in the table below, together with multi-client library and oil and natural gas assets) are not necessarily indicative of the earnings of the related property and equipment during the period. The geographic classification of income statement amounts listed below is based upon location of performance or, in the case of multi-client seismic data sales, the area where the survey was physically located.

Information by geographic region is summarized as follows:

(In thousands of dollars)	Americas	UK	Norway	Asia/ Pacific	Africa	Middle East /Other	Elimination of affiliated sales	Total
Revenue, unaffiliated companies:								
2004	**269 629**	**191 745**	**340 367**	**191 703**	**112 503**	**29 514**	**---**	**1 135 461**
2003	317 183	204 485	267 892	115 365	145 385	70 348	---	1 120 658
2002	220 633	254 087	224 856	142 170	80 393	70 197	---	992 336
Revenue, includes affiliates:								
2004	**269 629**	**194 712**	**347 154**	**191 703**	**112 503**	**29 514**	**(9 754)**	**1 135 461**
2003	317 183	206 585	273 114	115 365	145 385	70 348	(7 322)	1 120 658
2002	221 233	256 992	227 774	142 200	80 393	70 197	(6 453)	992 336
Total assets:								
2004	**343 941**	**912 664**	**471 913**	**79 462**	**20 334**	**6 889**	**---**	**1 835 203**
2003	428 500	827 686	527 856	107 691	4 056	23 178	---	1 918 967
Capital expenditures (cash):								
2004	**7 955**	**40 812**	**96 813**	**1 975**	**---**	**817**	**---**	**148 372**
2003	11 385	7 160	37 246	358	---	1 561	---	57 710
2002	10 390	21 483	28 415	192	---	279	---	60 759

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2004, 2003 and 2002.

For the years ended December 31, 2004, 2003 and 2002, 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,						
	2004		2003			2002	
Segments serving customer:	25%	10%	19%	12%	10%	15%	11%
Marine Geophysical	X	X	X	X	X	X	X
Onshore					X		
Production	X	X	X	X		X	X
Pertra	X		X				X
Reservoir/Shared Services/Corporate	X	X	X			X	X

Note 5 Investments in Associated Companies

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

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Corporations and limited partnerships:			
Geo Explorer AS	1 827	119	(524)
Atlantic Explorer (IoM) Ltd.	(80)	---	---
Calibre Seismic Company	---	(4)	(37)
FW Oil Exploration LLC	---	---	(677)
Ikdam Production, SA	2 030	(5)	(165)
Triumph Petroleum	---	787	(288)
Aqua Exploration Ltd.	1 500	---	---
Total	5 277	897	(1 691)

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

(In thousands of dollars)	Book value December 31, 2003	Share of income 2004	Paid-in capital (dividends) 2004	Currency translation 2004 (a)	Book value December 31, 2004	Ownership percent as of December 31, 2004
Corporations and limited partnerships:						
Geo Explorer AS	1 373	1 827	(3 018)	---	182	50.0%
Atlantic Explorer (IoM) Ltd.	112	(80)	---	---	32	50.0%
Ikdam Production, SA	4 807	2 030	---	(1 426)	5 411	40.0%
Aqua Exploration Ltd.	---	1 500	(1 500)	---	---	---
General partnerships	94	---	---	1	95	---
Total	6 386	5 277	(4 518)	(1 425)	5 720	

(a) Currency translation relating to the investment in Ikdam Production relates to reversal of the historical currency adjustments recorded against equity.

Note 6 Interest Expense

Interest expense includes the following:

(In thousands of dollars)	Years ended December 31, 2004	2003	2002
Interest expense, gross	(112 694)	(107 934)	(135 223)
Interest on trust preferred securities	---	(8 536)	(14 974)
Interest on multi-client library securitization securities	---	(1 685)	(6 634)
Interest capitalized	1 461	2 696	5 579
Total interest expense	(111 233)	(115 459)	(151 252)

Note 7 Other Financial Items, Net

Other financial items, net, consists of:

(In thousands of dollars)	Years ended December 31, 2004	2003	2002
Interest income	4 840	5 432	3 951
Foreign currency loss	(8 024)	(8 315)	(8 869)
Gain on TES (a)	--	---	54 149
Write-off of deferred debt costs and issue discounts	---	(13 152)	---
Other (b)	(7 998)	(11 146)	(6 428)
Other financial items, net	(11 182)	(27 181)	42 803

(a) 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 Mortgages Notes and its trust preferred securities. In 2002, all outstanding TES contracts were settled.

(b) Includes interest variation paid relating to UK leases for the years ended December 31 2004, 2003 and 2002 of approximately $6.3 million, $6.4 million and $3.9 million, respectively.

Note 8 Income Taxes

The provision (benefit) for income taxes consists of the following:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Current taxes:			
Norway	(397)	5 025	2 096
Foreign	1 987	26 050	22 541
Deferred taxes:			
Norway	28 526	22 620	88 160
Foreign	(1 558)	(26 878)	96 417
Total	28 558	26 817	209 214
Net taxes related to discontinued operations	---	(381)	(7 270)
Income tax expense	28 558	26 436	201 944

The net provision (benefit) for the year ended December 31, 2004, 2003, and 2002 includes $0.3 million, ($6.9) million and $16.2 million, respectively, related to contingent tax issues.

The provision (benefit) for income taxes differs from the amounts computed when applying the Norwegian statutory tax rate to income (loss) before income taxes (inclusive of discontinued operations) as a result of the following:

	Years ended December 31		
(In thousands of dollars)	2004	2003	2002
Income (loss) before income taxes:			
Norway	(75 555)	(528 118)	(498 373)
Foreign	49 836	(263 954)	(538 107)
Total	(25 719)	(792 072)	(1 036 480)
Norwegian statutory rate	28 %	28 %	28 %
Provision (benefit) for income taxes at the statutory rate	(7 201)	(221 780)	(290 214)
Increase (reduction) in income taxes from:			
Foreign earnings taxed at other than statutory rate	(7 422)	24 871	69 537
Petroleum surtax (a)	14 078	16 911	1 599
Prior year adjustments related to exit shipping tax regime, unresolved issues, etc. (b)	3 047	55 273	4 245
Unrealized exchange losses (permanent difference)	(2 578)	4 169	91 020
Permanent items, including 2002 goodwill impairment	15 165	30 020	56 683
Deferred tax assets not recognized in balance sheet	13 469	131 983	258 609
Other	---	(14 630)	17 735
Income tax expense	28 558	26 817	209 214

(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%.
(b) Prior year adjustments relate only to deferred taxes for which a valuation allowance was recognized.

Tax effects of the Company's temporary differences are summarized as follows:

	December 31,	
(In thousands of dollars)	2004	2003
Property and equipment and long-term assets	1 822	(31 382)
Tax losses carried forward	(262 458)	(311 351)
Deferred gains (losses)	(15 994)	(13 087)
Tax credits	(2 893)	(3 855)
Expenses deductible when paid	(68 091)	(56 774)
Other temporary differences	(6 071)	3 861
Total net deferred tax (asset) liability	(353 685)	(412 588)
Deferred tax assets not recognized in balance sheet	384 905	416 841
Net deferred tax (asset) liability in balance sheet	31 220	4 253
Deferred tax (asset) liability – Norwegian	30 854	4 253
Deferred tax (asset) liability – Foreign	366	---
Net deferred tax (asset) liability in balance sheet	31 220	4 253

Net deferred tax liability in the balance sheet is presented as:

(In thousands of dollars)	December 31, 2004	2003
Deferred tax liabilities (short term)	2 775	---
Deferred tax liabilities (long term)	28 445	4 253
Net deferred tax (asset) liability in balance sheet	31 220	4 253

The Company has significant tax losses carried forward and other deferred tax assets that are not recognized in the balance sheet. The Company has rejected recognition of net deferred tax assets to the balances sheet due to cumulative losses in recent years and considerable uncertainties in regards to future utilization of these losses. To the extent that the Company continues to generate deferred tax assets, these will not be recognized to the balance sheet until future earnings and utilization is substantiated.

Tax losses carried forward and expiration periods per December 31, 2004 are summarized as follows:

(In thousands of dollars)		
Brazil	8 350	No expiry
Norway	471 679	2011-2014
Singapore	32 605	No expiry
UK	302 055	No expiry
US	72 570	2019-2025
Other	10 023	2011/unlimited
Losses carried forward	897 282	

It is the Company's current policy that unremitted earnings of certain international operations, which reflect full provision for non-Norwegian income taxes, have no provision for Norwegian taxes, as these earnings are expected to be reinvested indefinitely.

The Company has previously not accrued for the deferred taxes related to subsidiaries in the Norwegian tonnage tax based on the reinvestment plans and dividend policy of those companies. In 2003 the Company decided that two subsidiaries will exit the Norwegian tonnage tax regime, and the estimated gross deferred tax effect of $37.8 million was incorporated in 2003.

The Norwegian Central Tax Office (CTO) has not yet finalized the tax assessment of PGS Shipping AS and PGS Shipping (IOM) Ltd (the latter being taxed as a CFC in Norway) for 2002, when the companies withdrew from the Norwegian tonnage tax regime. The pending issue is related to fair value of the vessels owned by these companies (10 seismic vessels and the FPSOs *Petrojarl Varg* and *Ramform Banff*). The Company based such exit 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 9 Earnings Per Share

Earnings per share were calculated as follows:

	Years ended December 31, 2004	2003	2002
Net income (loss) (in thousands of dollars)	(54 277)	(819 203)	(1 246 252)
Basic and diluted income (loss) per share	$ (2.71)	$ (40.96)	$ (12.06)
Basic and diluted shares outstanding	20 000 000	20 000 000	103 345 987

For the year ended December 31, 2003, basic and diluted shares outstanding are presented as 20 000 000, which is equal to the numbers of shares issued as part of the restructuring of the Company during 2003. At the same time, all previously existing shares of 103 345 987 were cancelled.

At December 31, 2003, all prior share-based compensation plans had been cancelled, resulting in no differences between basic and diluted earnings per share. Basic earnings per share and diluted earnings per share for the year ended December 31, 2002 were equal, since both basic and diluted earnings per share were calculated using the weighted average shares outstanding for the period and there was no dilutive effect of any equity instrument issued.

Note 10 Commitments and Contingencies

Leases:

The Company has operating lease commitments expiring at various dates through 2015. The Company also has capital lease commitments for mainly onshore-based equipment, expiring at various dates through 2008. Future minimum payments related to non-cancellable operating and capital leases, with lease terms in excess of one year, existing at December 31, 2004 are as follows:

	December 31, 2004	
(In thousands of dollars)	Operating leases	Capital leases
2005	36 436	27 364
2006	22 818	21 224
2007	22 612	6 904
2008	22 609	6 632
2009	21 283	---
Thereafter	37 875	---
Total	163 633	62 124
Imputed interest		(3 385)
Net present value		58 739
Current portion		(25 583)
Long-term portion		33 156

Future minimum payments related to non-cancellable operating leases reflect $7.1 million of sublease income for 2005, 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:

(In thousands of dollars)	December 31, 2004
Marine seismic and support vessels	7 135
Onshore seismic equipment	213
FPSO shuttle and storage tankers	60 000
Operations computer equipment	63
Buildings	95 714
Fixtures, furniture and fittings	508
Total	163 633

Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above, is the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. PGS is obliged to keep the vessel for as long as *Ramform Banff* produces the Banff field, which could extend to 2015 depended on the client. The maximum payment for the lease through 2015 is $119.4 million.

Rental expense for operating leases, including leases with terms of less than one year, was $61.2 million, $97.6 million and $112.9 million for the years ended December 31, 2004, 2003 and 2002, respectively. Rental expense for operating leases for the years ended December 31, 2004, 2003 and 2002 reflects $10.3 million, $18.0 million and $21.7 million, respectively, in sub-lease income related to time charter of FPSO shuttle tankers to a third party.

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 ("Interest Rate Differential"). There are no limits on either of these indemnities. Reference is also made to the description in Note 2 – UK Leases.

The Company believes it is unlikely that these defeased leases will be successfully challenged by the UK tax authorities and has not recorded any liability related to these overall Tax Indemnities in its Norwegian GAAP financial statements. In November 2004, the House of Lords in the United Kingdom rejected an appeal from the UK tax authorities relating to capital allowances associated with another entity's defeased lease transaction. Consequently, the Company believes that this final judgment further reduces the risk that the Company's UK leases will be successfully challenged.

The UK tax authorities have raised a specific 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 the 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).

With respect to the Interest Rate Differential, the Company, following the restatement described in Note 1, deferred a portion of the gains related to its UK leases for liabilities related to the difference, at inception of the lease, between the projected future distribution from the Payment Banks and the projected lease payments, based on forward interest rate curves. These deferred gains are amortized over the term of the leases. 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 ("Additional Required Rental Payments"). Additional required Rental Payments were $6.3 million, $6.4 million and $3.9 million for the years ending December 31, 2004, 2003 and 2002, respectively. The Company amortized deferred gains of $0.9 million, $0.6 million and $0.8 million for the years ending December 31, 2004, 2003 and 2002, respectively, which are reported in other financial items, net. The deferred gains are recorded at exchange rates at the balance sheet dates and resulted in unrealized foreign exchange losses of $1.3 million, $1.5 million and $1.4 million for the years ended December 31, 2004, 2003 and 2002, respectively, and which are presented as other financial items in the consolidated statement of operations.

Currently, interest rates are below the Assumed Interest Rates, and based on forward market rates for Sterling LIBOR, as of December 31, 2004 the net present value of Additional Required Rental Payments aggregated GBP 29.6 million, using an 8% discount rate, off which GBP 1.0 million was accrued at December 31, 2004. As of December 31, 2003, such accrual was GBP 1.1 million.

In addition, the Company has, as described above, deferred gain in relation to Interest Rate Differential amounting to GBP 8.3 million and GBP 8.8 million as of December 31, 2004 and 2003, respectively.

Note 11 Loss Contracts

As of December 31, 2004 and 2003, the Company had no accrued loss contracts.

Note 12 Long-Lived Intangible Assets

Long-lived intangible assets consist of the following:

	December 31,	
(In thousands of dollars)	2004	2003
Software products	39	---
Licenses and patents	2 036	1 975
Total	2 075	1 975

Note 13 Goodwill

The Company recognized $42.9 million in impairment of goodwill (excluding goodwill related to discontinued operations) in 2002. No goodwill existed as of December 31, 2004 and 2003. The Company expensed amortization on goodwill amounting to $1.2 million for the year ended December 31, 2002, while no amortization was expensed in the years ended December 31, 2004 and 2003.

Note 14 Property and Equipment, Net (including capital leases)

(In thousands of dollars)	Seismic vessels-/ equipment	Production vessels-/ equipment	Fixures, furnitures and fittings	Buildings-/ other	Total
Purchase costs:					
Cost per December 31, 2003	1 060 703	1 705 644	50 804	11 744	2 828 895
Additions to costs	53 662	988	8 910	754	64 314
Retirements	(41 126)	(112 932)	(1 121)	(32)	(155 211)
Translation adjustments/other	10 581	1	(1 977)	(186)	8 419
Cost per December 31, 2004	1 083 820	1 593 701	56 616	12 280	2 746 417
Accumulated depreciation/- impairments:					
Depreciation per December 31, 2003	536 212	339 474	40 011	6 973	922 670
Impairments per December 31, 2003	154 189	661 738	---	1 200	817 127
Depreciation 2004	63 342	39 663	4 830	912	108 747
Retirements 2004	(37 777)	(112 932)	(373)	(1)	(151 083)
Translation adjustments/other	7 075	(1)	(411)	14	6 677
Depreciation per December 31, 2004	568 852	266 204	44 057	7 898	887 011
Impairments per December 31, 2004	154 189	661 738	---	1 200	817 127
Balance per December 31, 2004	360 779	665 759	12 559	3 182	1 042 279

The Company had $636.4 million and $656.7 million in property and equipment under UK leases at December 31, 2004 and 2003, 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 principle 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 not presented separately .

The following table summarizes depreciation expense, (see Note 32 for impairment details):

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Depreciation expense, net of amount capitalized into multi-client library	104 765	123 056	132 818
Depreciation expense capitalized into multi-client library	3 982	13 095	31 528

No interest was capitalized into property and equipment for the years ended December 31, 2004, 2003 and 2002, respectively.

For details of the estimated useful life's for the Company's property and equipment per December 31, 2004, see Note 2 for all details.

Note 15 Multi-Client Library

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

	Net book value December 31,	
(In thousands of dollars)	2004	2003
Completed surveys:		
Completed during 1998, and prior years	2 966	26 800
Completed during 1999	12 432	31 989
Completed during 2000	22 434	38 312
Completed during 2001	112 617	144 353
Completed during 2002	38 341	53 527
Completed during 2003	33 436	57 758
Completed during 2004	10 334	---
Completed surveys	232 560	352 739
Surveys in progress	8 036	14 961
Multi-client library	240 596	367 700

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

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Impairment charges (note 32)	---	241 481	268 403
Amortization expenses (a)	173 276	155 648	212 887
Interest capitalized into multi-client library	1 461	2 696	5 579
Depreciation capitalized into multi-client library	3 982	13 095	31 528

(a) Amortization expenses for the year ended December 31, 2004, includes $31.3 million of additional non-sales related amortization. This amount includes $7.8 million in minimum amortization and $23.5 million of non-sales related amortization to reflect reduced fair value of future sales on certain individual surveys. For the years ended December 31, 2003 and 2002, the Company recognized $4.0 million and $39.8 million, respectively, in minimum amortization.

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

	December 31, 2004
(In thousands of dollars)	Minimum future amortizations
During 2005	72 271
During 2006	97 010
During 2007	34 884
During 2008	23 988
During 2009	9 155
During 2010	3 288
Future minimum amortization	240 596

These minimum amortization requirements are calculated as if there were no future sales related to these surveys. 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 minimum amortization charges in a year even if the aggregate amount of ordinary amortization charges recognized exceeds the aggregate minimum amortization charges.

Note 16 Oil and Natural Gas Assets

The Company's oil and natural gas assets consist of the Company's investment in 70% of the production license 038, which includes the Varg-field, on the Norwegian continental shelf of the North Sea. The capitalized value is as follows:

(In thousands of dollars)	2004	2003
Net book-value beginning of year	30 678	17 324
Effect of accounting principle change, January 1, 2003	---	(3 393)
Capital expenditures, cash and accrued	81 030	44 902
Produced, but not delivered oil (a)	---	(3 382)
Depreciation, depletion and amortization	(36 314)	(20 429)
Expensed capitalized exploration costs (b)	(11 438)	(4 344)
Net book-value at end of year	63 956	30 678

(a) Reclassified to other current assets in 2003.
(b) Classified as depreciation and amortization in the cosolidated statement of operations.

The Company expensed geological and geophysical costs for total $8.6 million, $4.3 million and $3.3 million for the years ended December 31, 2004, 2003 and 2002 respectively. Such costs are included in cost of sales in the consolidated statements of operations.

Note 17 Other Financial Assets

Other financial assets consists of:

	December 31,	
(In thousands of dollars)	2004	2003
Governmental grants and contractual receivables	17 204	11 660
Other long-term receivables	18 545	15 108
Deferred debt issue costs	4 356	2 755
Total	40 105	29 523

Note 18 Accounts Receivables, net

Accounts receivable, net, consist of the following:

(In thousands of dollars)	December 31, 2004	2003
Accounts receivable - trade	162 775	129 192
Allowance for doubtful accounts	(1 492)	(3 468)
Unbilled revenue and other receivables	40 561	46 784
Total	201 844	172 508

Development of allowance for doubtful accounts is as follows:

(In thousands of dollars)	2004	2003
Beginning balance	3 468	3,857
New and additional allowances	977	3 325
Write-offs and reversals	(2 953)	(3 714)
Ending balance	1 492	3 468

Note 19 Other Current Assets

Other current assets consist of the following:

(In thousands of dollars)	December 31, 2004	2003
Prepaid operating expenses	13 053	18 720
Spare parts, consumables and supplies	12 840	11 348
Prepaid taxes	15 821	11 256
Shares available for sale	9 689	—
Produced oil, not lifted	5 037	5 377
Advances to agents	723	5 123
Other	13 032	12 913
Total	70 195	64 737

(a) Shares available for sale relates to the Company's investment in Endeavour originally acquired through contribution of licenses to use PGS seismic data in the North Sea. The Company owns approximately 3.3% of the shares in the Endeavour, which had an original cost price of $3.8 million. Under the terms of an agreement with Endeavour, the Company may not sell any of its shares for the first twelve month from the conversion date (February 2004); from twelve to twenty-four months, the Company may sell up to one third of its equity per quarter. Revaluation of the shares (a gain of $5,9 million in 2004) has been recorded directly to shareholder's equity (see consolidated statements of changes in shareholders' equity).

Note 20 Restricted Cash

Restricted cash consist of:

(In thousands of dollars)	December 31, 2004	2003
Current:		
Bid / performance bonds	11 674	27 265
Restricted payroll withholding taxes	4 323	4 027
Other	9 480	9 831
Total restricted cash, current	25 477	41 123
Long-term – bond escrow	10 014	10 014
Total	35 491	51 137

Note 21 Shareholder Information

As of December 31, 2004, Petroleum Geo-Services ASA had a share capital of NOK 600 million divided on a total of 20,000,000 shares, of par value NOK 30, each fully paid in. All shares have equal voting rights and are entitled to dividends. Any distribution of the Company's equity is dependent on the approval of the shareholders, and the ability to make distributions are limited by certain debt covenants and Norwegian Corporate Law (see Note 25).

The 20 largest shareholders in Petroleum Geo-Services ASA were as follows:

	December 31, 2004	
	Total shares	Ownership percent
Citibank N.A., holder of American Depositary Shares ("ADS") (nominee) (a)	3 404 070	17.0
Citibank N.A., holder of American Depositary Shares ("ADS") (nominee) (a)	3 194 565	16.0
Umoe Invest AS	1 012 444	5.1
JP Morgan Chase Bank (nominee)	752 333	3.8
Bear Stearns Securities (nominee)	580 951	2.9
Morgan Stanley & Co. (nominee)	557 572	2.8
Goldman Sachs & Co. (nominee)	531 034	2.6
JP Morgan Chase Bank (nominee)	495 160	2.5
Euroclear Bank S.A. (nominee)	454 060	2.3
Goldman Sachs International (nominee)	432 643	2.1
State Street Bank & Trust Co. (nominee)	348 621	1.7
Odin Norge	306 906	1.5
Skandinaviska Enskilda Banken (nominee)	293 879	1.5
Vital Forsikring ASA	284 230	1.4
Odin Norden	276 300	1.4
Morgan Stanley & Co. (nominee)	253 767	1.3
Deutsche Bank AG	217 213	1.1
Mellon Bank (nominee)	210 678	1.0
KAS Depositary Trust (nominee)	200 000	1.0
Bank of New York	179 691	0.9
Other shareholders	6 013 883	30.1
Total	20 000 000	100.0

(a) On the basis of existing depository agreements regarding owners of the ADS's, the table above does not show the beneficial owner of shares.

Shares and ADS owned or controlled by members of the Board of Directors, Chief Executive Officer and other executive officers were as follows:

	December 31, 2004	
	Total shares	Ownership percent
Board of Directors:		
Jens Ulltveit-Moe, Chairman (a)	1 012 444	5.1
Keith Henry, Vice Chairman	---	---
Francis Gugen	---	---
Harald Norvik	---	---
Rolf Erik Rolfsen	---	---
Clare Mary Spottiswoode	---	---
Anthony Tripodo	---	---
Marianne Johnsen (Deputy board member)	---	---
John Reynolds (Deputy board member)	---	---
Chief Executive Officer and other executive officers:		
Svein Rennemo, Chief Executive Officer	3 000	(b)
Gottfred Langseth	---	---
Rune Eng	1 000	(b)
Eric Wersich	---	---
Sverre Skogen	---	---
Erik Haugane	---	---
Anthony Ross Mackewn	76	(b)
Andreas J. Enger	---	---

(a) Controlled through Umoe AS.
(b) Less than 1% of the Company's share as of December 31, 2004.

Note 22 Share-Based Compensation

In connection with the restructuring of the Company in 2003, all shares in the Company were cancelled (see Note 25 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.

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

	December 31, 2003		December 31, 2002	
(In thousands of options)	Options	Weighted average exercise price	Options	Weighted average exercise price
Outstanding at beginning of year	4 973.5	135 NOK	8 635.4	142 NOK
Forfeited/cancelled	(4 973.5)	135 NOK	(3 661.9)	151 NOK
Outstanding at end of year	---	---	4 973.5	135 NOK

Note 23 Other Long-Term Liabilities

Other long-term liabilities consist of the following:

	December 31,	
(In thousands of dollars)	2004	2003
Deferred gain UK leases	15 983	15 547
Accrued pension costs	32 364	26 254
Asset retirement obligations	58 518	49 303
Tax contingencies	25 522	21 720
Other	955	1 191
Total	133 342	114 015

Note 24 Short-term debt and current portion of long-term debt and capital lease obligations

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

	December 31,	
(In thousands of dollars)	2004	2003
Short-term debt	1 962	---
Current portion of long-term debt (Note 25)	17 828	18 512
Current portion of capital leases (Note 10)	25 583	15 975
Total	45 373	34 487

Note 25 Financial Restructuring and Debt

Financial restructuring completed in 2003:

On July 29, 2003, the Company voluntarily filed a petition for protection under Chapter 11 of the United States Bankruptcy Code ("Chapter 11"). The filing was based on a financial restructuring plan that was pre-approved by a majority of banks and bondholders as well as a group of PGS' largest shareholders. PGS emerged from Chapter 11 November 5, 2003, just 100 days after filing.

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

- $746 million of 7-year, 10% senior unsecured notes
- $250 million of 3-year, 8% senior unsecured notes
- $4.8 million of 8-year, unsecured senior term loan facility (which was fully repaid in May 2004)
- 91% of PGS' 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
- $40.6 million of cash distributed by PGS, of which $17.9 million was distributed in December 2003 and the remainder in May 2004.

In accordance with the plan, the existing share capital, consisting of 103 345 987 shares, par value NOK 5, was cancelled and 20 000 000 new ordinary shares, par value NOK 30, were issued. The pre-restructuring shareholders received 4% or 800 000 of the new ordinary shares (one new share per 129 old shares), 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.

Owners of $144 million of trust preferred securities received 5% or 1 000 000 of the new ordinary shares.

Interest bearing debt of the Company post restructuring was $1 189 million, a reduction of $1 283 million. The financial restructuring involved only the parent company and did not involve operating subsidiaries, which continued full operations, leaving customers, lessors, vendors, employees and subsidiary creditors unaffected.

Long-Term Debt:

Long-term debt consists of the following:

	December 31,	
(In thousands of dollars)	2004	2003
Unsecured:		
10% Senior Notes, due 2010	745 949	745 950
8% Senior Notes, due 2006	250 000	250 000
Libor + 1.15% Unsecured senior term loan	---	4 811
Secured:		
8.28% First Preferred Mortgage Notes, due 2011	98 920	109 120
Other loans, due 2005 - 2006	8 149	17 306
Total debt	1 103 018	1 127 187
Less current portion	(17 828)	(18 512)
Total long-term debt	1 085 190	1 108 675

Aggregate maturities of long-term debt as of December 31, 2004 are as follows:

(In thousands of dollars)	December 31, 2004
Year of repayment:	
2005	17 828
2006	263 231
2007	12 900
2008	14 040
2009	15 160
Thereafter	779 859
Total	1 103 018

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 payment 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-annually, 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.

Bank Credit Facilities:

In March 2004, the Company entered into a secured $110.0 million credit facility 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 borrowing under the credit facility is LIBOR plus 2%. The credit facility is an obligation of PGS ASA and is guaranteed by certain material subsidiaries.

Short-Term Debt:

The Company borrows short-term debt with various international banks based on short-term working capital requirements. No such borrowings were made during 2004 and 2003 and no short-term debt was outstanding at December 31, 2004 and 2003. Net short-term debt is $2.0 million of which $1.8 million is related to purchase of the seismic vessel *Falcon Explorer*.

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 debt, to $1.5 billion. These debt agreements also restrict, among other things: payment of dividends; ability to place liens on Company 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. Specifically, certain financing agreements do not allow the Company to pay dividends or make similar distribution until the $250 million 8% Senior Notes, due 2006, are repaid.

Certain of the loan and lease agreements and 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. The Company has received waivers and amendments allowing it to report under N GAAP in lieu of U.S. GAAP until June 30, 2005.

The Company is in compliance with its loan covenants as of December 31, 2004 and currently.

Pledged Assets:
Certain seismic vessels and seismic equipment with a net book value of $55.2 million and $60.6 million at December 31, 2004 and 2003, respectively, are pledged as security on the Company's debt shown as secured in the table above and as short-term debt. In addition *Petrojarl Varg* and the shares of KS Petrojarl 1 AS and Golar-Nor Offshore AS, 98.5% owners of *Petrojarl 1*, are pledged as security for the $ 110 million bank credit facility. The book value of *Petrojarl Varg* and shares in KS Petrojarl 1 AS and Golar-Nor Offshore AS totals $166.9 million at December 31, 2004.

Letter of Credit and Guarantees:
The Company had aggregate outstanding letters of credit and related types of guarantees, not reflected in the accompanying consolidated financial statements, of $30.1 million and $31.0 million at December 31, 2004 and 2003, respectively.

Subsequent Event:
In February 2005 the Company established an additional overdraft facility of NOK 50 million as part of its Norwegian cash pooling system.

On March 8, 2005 the Company sent a notice of redemption relating to $175 million of its $250 million 8 % Senior Notes, due 2006 ("Notes"). The Notes, in the amount of $175 million, will be redeemed on April 7, 2005 at a redemption price equal to 102.00% of the principal amount of such Notes, plus accrued and unpaid interest to the redemption date.

Note 26 Accrued Expenses

Accrued expenses consist of the following:

	December 31,	
(In thousands of dollars)	2004	2003
Accrued employee benefits	37 659	33 901
Accrued vessel operating expenses	17 080	25 628
Customer advances and deferred revenue	12 070	15 014
Accrued commissions	9 683	5 088
Accrued interest expenses	3 394	1 805
Accrued debt restructuring expenses	---	25 320
Other	35 562	50 387
Total	115 448	157 143

Note 27 Derivative Financial Instruments and Risk Management

The finance department of Petroleum Geo-Services ASA is responsible for cash management, financial management and management of financial risk for the holding company and subsidiaries included in the consolidated group.

Notional Amounts and Credit Exposure of Derivative Financial Instruments:
Accounting for financial instruments follow the underlying intention of the contract. The contract is defined either as a hedge or as held-for-sale, upon entering into the contract. Periodically, the Company makes use of such financial instruments in order to hedge against foreign currency exchange risks, but they are not used for speculative purposes.

The notional amounts of the derivative financial instruments summarized below do not reflect the values exchanged by the parties and, therefore, are not a measure of the Company's exposure. The amounts ultimately exchanged are calculated on the basis of the notional amounts and the other terms of the respective derivative financial instruments.

Receivables Credit Risk:
The Company extends credit to various companies in the oil and gas industry worldwide, which may be affected by changes in economic or other external conditions. At December 31, 2004 and 2003, accounts receivable (both current and long-term) were primarily from multi-national integrated oil companies and independent oil and 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 its customers and has provided for potential credit losses through an allowance for doubtful accounts. Management does not believe that the Company is exposed to concentrations of credit risk that are likely to have a material adverse impact on the Company's financial position or results of operations.

Foreign Currency Exchange Risk Management:
The Company periodically enters into forward exchange contracts and option contracts to hedge against foreign currency exchange risks associated with certain firm commitments and transactions related to property and equipment. The Company is most sensitive to changes in the Norwegian Kroner to US dollar exchange rates. There were no foreign currency exchange contracts outstanding at December 31, 2004 and 2003.

Fair Values of Financial Instruments:
The carrying amounts of cash and cash equivalents, 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 these instruments. The carrying amounts and the estimated fair values of the Company's long-term financial instruments are summarized as follows:

	December 31, 2004		December 31, 2003	
(In thousands of dollars)	Carrying amounts	Fair values	Carrying amounts	Fair values
Debt	1 103 018	1 218 386	1 127 187	1 185 313

The fair values of the Company's long-term debt instruments are estimated using quotes obtained from dealers in such financial instruments.

Interest Rate Exposure:
The Company is exposed to interest rate risk due to money market activities relating to investments and cash flows. Changes in interest rates can also affect the fair values of assets and liabilities. Interest income (expense), including actual interest payments, are affected by changes in interest rates. The majority of the Company's business activities are conducted in USD, GBP and NOK. This gives rise to interest rate exposure in these currencies. As at December 31, 2004, virtually all loans were denominated in USD, and approximately 99% of these loans had a fixed rate of interest.

The Company engages from time-to-time in interest rate derivatives. As at December 31, 2004, the Company had outstanding interest swap agreements in the aggregate notional amount of $10.3 million, which do not qualify for hedge accounting. The market value of these agreements were approximately ($0.5) million.

Foreign Exchange Exposure:
The reporting currency applied to the consolidated accounts is USD, and the Company also applies this currency for internal reporting of key performance indicators.

The Company's net income (loss) is affected by changes in exchange rates, as profits and losses reported by subsidiaries which do not use USD as the functional currency, are translated to USD using an average rate of exchange for the period. The significant loans and assets held within the Company are denominated in USD.

The Company's cash flows are denominated primarily in USD, NOK and GBP. The Company generally attempts to minimize net cash flow exposure in NOK and GBP through business transactions and currency hedging instruments. At times, a significant currency risk can exist based on fluctuations in exchange rates between USD, NOK and GBP.

The Company did not have any currency hedging instruments as of December 31, 2004.

Commodity Derivative:
We are exposed to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2004 (combined) was 5 317 134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2004 and 2003, we did not have any outstanding 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. Of total amount sold forward, 250 000 barrels sold forward at an average price of $29.91 per barrel was not yet delivered at December 31, 2004 and was delivered in early January 2005. Estimated fair value of the contract per December 31, 2004 was a net liability of $2.6 million.

Note 28 Retirement Plans

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, 2004, 1,069 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:

	December 31,	
(In thousands of dollars)	2004	2003
Projected benefit obligations at beginning of year	93 008	72 310
Adjusted at beginning of year	---	6 820
Service cost	10 198	8 792
Interest cost	5 145	4 454
Employee contributions	968	1 031
Payroll tax	198	1 434
Actuarial (gain) loss, net	(2 045)	(3 204)
Benefits paid	(1 212)	(1 676)
Exchange rate effects	9 620	3 047
Projected benefit obligations at end of year	115 880	93 008

Change in plan assets:

(In thousands of dollars)	December 31, 2004	2003
Fair value of plan assets at beginning of year	53 332	48 144
Adjustment at beginning of year	(1 347)	530
Return on plan assets	4 130	3 796
Employer contributions	8 383	8 728
Employee contributions	968	1 031
Benefits paid	(1 212)	(1 676)
Exchange rate effects	7 311	(7 221)
Fair value of plan assets at end of year	71 565	53 332

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

(In thousands of dollars)	December 31, 2004	2003
Funded status	(44 315)	(39 677)
Unrecognized actuarial loss	15 554	15 494
Unrecognized prior service cost	---	23
Unrecognized transition obligation	---	170
Net amount recognized as accrued pension liability	(28 761)	(23 990)

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

(In thousands of dollars)	December 31, 2004	2003
Other long-term assets	3 603	2 264
Other long-term liabilities	(32 364)	(26 254)
Net amount recognized as accrued pension liability	(28 761)	(23 990)

The accumulated benefit obligation for all defined benefit pension plans was $104.3 million and $72.7 million as of December 31, 2004 and 2003, respectively.

Assumptions used to determine benefit obligations:

	2004		2003	
	Norway	UK	Norway	UK
Discount rate	5.3%	5.3%	6.0%	5.3%
Return on plan assets	6.3%	7.5%	7.0%	7.5%
Benefit increase	3.0%	3.0%	3.0%	4.7%
Annual adjustment to pensions	3.0%	3.0%	3.0%	3.0%

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

(In thousands of dollars)	Years ended December 31, 2004	2003	2002
Service cost	10 198	8 792	8 103
Interest cost	5 145	4 454	3 108
Expected return on plan assets	(4 130)	(3 796)	(3 439)
Amortization of actuarial loss	1 119	2 142	86
Amortization of prior service cost	---	3	2
Amortization of transition obligation	---	20	15
Adjustment to minimum liability	(1 874)	---	---
Administration costs	99	---	---
Payroll tax	1 047	1 492	---
Net periodic pension cost	11 604	13 107	7 875

The Company's pension plan asset allocation at December 31, 2004 and 2003, by asset category, are presented by major plan group as follows:

	December 31, 2004		December 31, 2003		
(In thousands of dollars)	Norway	UK	Norway		UK
Fair value of plan assets	$ 40 111	$ 31 454	$ 15 280	$ 14 907	$ 23 145
Bonds	69%	---	62%	57%	---
Equity securities	16%	92%	13%	14%	74%
Real estate	12%	---	12%	13%	---
Other	3%	8%	13%	16%	26%
Total	100%	100%	100%	100%	100%

Substantially all employees not eligible for coverage under the defined benefit plans described above are eligible to participate in pension plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans. Under the Company's US defined contribution 401(k) plan, essentially all US employees are eligible to participate upon completion of certain-of-service requirements. The plan allows eligible employees to contribute up to 100% of compensation, subject to IRS and plan limitations, on a pre-tax basis, with a 2004 statutory cap of $13 000 ($16 000 for employees over 50 years). Employee pre-tax contributions are matched by the Company as follows; the first 3% are matched at 100%, the next 2% are matched at 50% of compensation. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $1.2 million, $1.4 million and $1.2 million for each of the years ended December 31, 2004, 2003 and 2002, respectively. Contributions to the plan by employees for these periods were $3.1 million, $3.3 million and $3.8 million, respectively. Aggregate employer and employee contributions under the Company's other plans for the years ended December 31, 2004, 2003 and 2002 totalled $1.6 million and $0.4 million (2004), $1.4 million and $0.4 million (2003) and $7.4 million and $3.0 million (2002).

Note 29 Related Party Transactions

At December 31, 2003 and 2002, 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 shares as Walter Herwig AS was de-merged) and chartered three vessels from that company in 2003 and 2002. Total lease expense recognized by the Company for 2003 and 2002 on these vessels was $7.4 million and $8.8 million, respectively, while there were no lease expense recognized during 2004.

As of December 31, 2004, the Chairman of the Board, Jens Ulltveit-Moe, through Umoe AS, controlled a total of 1,012,444 shares in Petroleum Geo-Services 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 was also chartering the MT *Nordic Yukon* up to 2003, from PGS on a time charter contract and paid $10.3 million, $20.1 million and $20.5 million to PGS under these contracts in 2004, 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 $0.7 million, $2.4 million and $1.8 million to Knutsen under this contract in 2004, 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.

Note 30 Supplemental Cash Flow Information

Cash paid during the year includes payments for:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Interest, net of capitalized interest	106 731	137 633	104 664
Interest on trust preferred securities / multi-client library securitization	---	544	13 566
Income taxes	29 751	13 096	15 938

The Company entered into capital lease agreements for new equipment aggregating $0.6 million and $57.4 million during the years ended December 31, 2003 and 2002, respectively, while there were no new capital lease arrangements during 2004.

Note 31 Salaries and Other Personnel Costs, Number of Employees, and Remuneration to the Board of Directors, Executive Officers and Auditors

Salary and social expenses that are included in cost of sales and selling, general and administrative costs and other operating income (expense) (including severance), excluding such costs relating to discontinued operations consist of:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Salaries	183 769	187 295	155 039
Social security	17 250	19 844	17 311
Pension	14 395	15 774	9 657
Other benefits	22 581	36 210	62 160
Total	237 995	259 123	244 167

In addition, the Company expensed salaries and other personnel costs related to discontinued operations of $1.9 million and $131.1 million for the years ended December 31, 2003 and 2002, respectively. During the year ended December 31, 2003 the Company expensed $12.4 million relating to a payroll tax claim for employees working in a subsidiary on Isle of Man, this expense, is not included in the table presented above (see Note 32).

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

	December 31,		
	2004	2003	2002
Marine Geophysical	1 115	1 143	1 356
Onshore	1 011	1 479	1 828
Production	501	515	520
Pertra	16	5	6
Reservoir/Shared Services/Corporate	256	235	252
Discontinued operations	---	---	41
Total	2 899	3 377	4 003

The Company had an average of 3 138, 3 690 and 4 574 employees during the years ended December 31, 2004, 2003 and 2002, respectively.

Chief Executive Officer (CEO) and other Executive Officers:
The table below provides information about the Company's executive officers as of December 31, 2004:

Name:	Position:	Executive officer since	Share Ownership
Svein Rennemo	President and Chief Executive Officer	2002	(*)
Gottfred Langseth	Senior Vice President and Chief Financial Officer	2004	---
Rune Eng	President – Marine Geophysical	2004	(*)
Erik Wersich	President - Onshore	2003	---
Sverre Skogen	President - Production	2004	---
Erik Haugane	Managing Director - Pertra	2003	---
Anthony Ross Mackewn	Senior Vice President - Geophysical	1999	(*)
Andreas J. Enger	Senior Vice President – Group Planning	2003	---

(*) Less than 1% of the Company's shares as of December 31, 2004.

CEO Svein Rennemo in 2004 received a salary of NOK 3 788 022 (approximately $556 432) and bonus totalling NOK 1 230 357 (approximately $180 730), of which NOK 650 000 (approximately $95 480) must be used to purchase shares in PGS. Svein Rennemo is not entitled to any pension benefits for which he receives an annual compensation of NOK 250 000 (approximately $36 723), which is included in the salary for 2004.

According to the performance bonus incentive scheme for the CEO established by the Board of Directors for 2004, the CEO is entitled to a cash bonus of up to 50% of annual base salary and a share purchase bonus of up to 30% of annual base salary. On the basis of achievement of certain group and individual key performance indicators, the Board of Directors resolved that the CEO for 2004 is entitled to a cash bonus of NOK 812 500 (approximately $132 523) and a share bonus of NOK 325 000 (approximately $53 009). The estimated bonus was accrued as of December 31, 2004. The net share bonus amount paid after withholding taxes must be used to buy PGS shares at market price and held for a minimum of three years.

The CEO held 3 000 shares in the Company as of December 31, 2004. Svein Rennemo has a mutual 12-month period of notice, with a deduction for other income, except capital income. During the period of notice, the CEO can not seek employment with companies that are in direct or indirect competition with PGS. The contract can be terminated without notice if Svein Rennemo fails to fulfil his contractual obligations. The other executive officers have similar provisions in their employment terms.

Aggregated payments to other executive officers for work carried out in their respective periods for the year ended December 31, 2004, was $2 241 446, including bonuses paid out during 2004. The aggregate benefits paid in to the various defined benefit plans for these executive officers as a group for 2004 was $121 894. As of December 31, 2004, executive officers owned a total of 1 076 shares (see Note 21 for additional information). None of the executive officers held any share options in the Company. The other executives officers hold employee agreements where period of notice vary from three to eighteen months.

For 2004 the Board of Directors established a performance bonus incentive scheme for the other executive officers similar to that for the CEO. Under this scheme, executive officers are entitled to a cash bonus of up to 40% of annual base salary and a share purchase bonus of up to 20% of annual base salary. Within these limits, bonuses were finally determined on the basis of achievement and overachievement of financial and non-financial performance targets. 100% of any amount received as share purchase bonus, on a net basis (amount paid after withholding tax), must be used to buy PGS shares at market price and held for a minimum of three years. The Board resolved that the bonus under the scheme for these executives for 2004 would be $465 592, an estimated amount for the scheme was accrued December 31, 2004.

Board of Directors:

The table below provides information about our directors as of December 31, 2004:

Name	Position	Director since	Term expire	Share ownership
Jens Ulltveit-Moe	Chairman	2002	2005	5.1% (a)
Keith Henry	Vice Chairman	2003	2005	---
Francis Gugen	Director	2003	2005	---
Harald Norvik	Director	2003	2005	---
Rolf Erik Rolfsen	Director	2002	2005	---
Clare Mary Spottiswoode	Director	2003	2005	---
Anthony Tripodo	Director	2003	2005	---

(a) Controlled through Umoe AS.

For the year ended December 31, 2004, the aggregate amount paid for compensation to the directors as a group, for services in all capacities was $575 240. This amount includes compensation paid to all persons who served as directors during any period.
As of December 31, 2004, the total number of shares and ADS's beneficially held by directors, were 1 012 444, and none of the directors held any share options in the Company (see Note 21 for additional information).

Remuneration to auditor:

Fees for audit and other services provided by the Company's auditor are as follows (exclusive VAT and including out of pocket expenses):

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Audit fees (a)	8 105	8 187	1 248
Other financial audit (b)	42	93	750
Fees for tax services (c)	134	182	51
All other fees (d)	---	541	540
Total	8 281	9 003	2 589

(a) Audit fees for 2004 include audit of the annual accounts up to March 31, 2005 ($3 199k) as well as incurred fees in 2004 (after May 31, 2004) for the audit of previous periods ($3 267k) and for the close of the 2003 audit in accordance with US GAAP and fresh start ($1 639k).
Audit fees for 2003 include audit of the annual accounts up to May 31, 2004 ($2 322k) as well as fees incurred during 2003/2004 (up to May 31, 2004) for the audit of previous periods ($3 966k) and for the fresh start audit under US GAAP ($1 899k).
(b) Other financial audit consists of fees for agreed upon procedures and other attestation services.
(c) Fees for tax services consist of fees for tax filing services, other tax assistance and reorganization.
(d) All other fees includes fees for assistance in connection with restructuring, refinancing and due diligence performed by banks in connection with the financial restructuring in 2003.

Note 32 Impairments of Long-Lived Assets and Other Operating Expense, net

As discussed in Note 1, in 2003 the Company made a full valuation of all its long-term assets and impaired assets down to their estimated recoverable amounts.

Impairment of long-lived assets consist of the following:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Multi-client library (Note 15)	---	(241 481)	(268 403)
Production related property and equipment (Note 14)	---	(367 021)	(425 214)
Seismic vessels, equipment and other geophysical assets (Note 14)	--	(129 084)	(56 169)
Licenses	---	(2 090)	---
Building leasehold improvements	---	(1 200)	---
Investments in associated companies (Note 5)	---	---	(14 744)
Goodwill (Note 13)	---	---	(42 886)
Total	---	(740 876)	(807 416)

Other operating expense, net consists of the following:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Costs relating to completion of 2002 U.S. GAAP accounts and re-audit 2001	(7 447)	(2 559)	---
Debt restructuring/refinancing/"fresh start"	(3 471)	(42 274)	(3 616)
Restructuring, termination costs and other non-recurring costs	(842)	(20 840)	(12 901)
Isle of Man, national insurance liability	---	(12 412)	---
Net gain related to cancelled merger with Veritas DGC Inc.	---	---	2 864
Other, net	---	---	(1 781)
Total	(11 760)	(78 085)	(15 434)

Note 33 Subsidiaries and Affiliated Companies

The ownership percentage in subsidiaries and affiliated companies as of December 31, 2004, are as follows:

Company	Jurisdiction	Shares/ voting rights
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%
Mulitklient Invest AS	Norway	100%
Pertra AS	Norway	100%
Petroleum Geo-Services, Inc.	USA	100%
Petroleum Geo-Services (UK) Ltd.	United Kingdom	100%
Seahouse Insurance Ltd.	Bermuda	100%
PGS Mexicana SA de CV	Mexico	100%
PGS Rio Bonito S.A.	Brazil	99%
PGS Administración y Servicios, S.A. de C.V	Mexico	100%
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	USA	50%
PGS Capital, Inc.	USA	100%
Diamond Geophysical Services Company	USA	100%
PGS Exploration (Nigeria) Ltd.	Nigeria	100%
PGS Data Processing Middle East SAE	Egypt	100%
PGS Data Processing, Inc.	USA	100%
Petroleum Geo-Services Asia Pacific Pte. Ltd.	Singapore	100%
PGS Australia Pty. Ltd.	Australia	100%
Atlantis (UK) Ltd.	United Kingdom	100%
PGS Egypt for Petroleum Services	Egypt	100%
Hara Skip AS	Norway	100%
PGS Exploration SDN BHD	Malaysia	100%
PGS Exploration, Inc.	USA	100%
PGS Exploration Pty. Ltd.	Australia	100%
PGS Ocean Bottom Seismic, Inc.	USA	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.	USA	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.	USA	100%
PGS Americas, Inc.	USA	100%
Seismic Energy Holding, Inc.	USA	100%
PGS Caspian AS	Norway	100%
PGS Multi Client Seismic Ltd.	Jersey	100%
PGS Marine Services (Isle of Man) Ltd.	Isle of Man	100%

Company	Jurisdiction	Shares/ voting rights
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	USA	50.1%
PGS Nopec (UK) Ltd.	United Kingdom	100%
PGS Nominees Ltd.	United Kingdom	100%
Petrojarl 4 DA	Norway	99.25%
SOH, Inc.	USA	100%
PGS Onshore (Canada), Inc.	USA	100%
PGS Venezuela de C.A.	Venezuela	100%
PGS Servicios C.A.	Venezuela	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%

Note 34 Adjusted EBITDA

Adjusted EBITDA, when used by the Company means Net Income (Loss) before income (loss) from associated companies, interest expenses, other financial items, taxes, depreciation and amortization, other operating (income) expense, impairment of long-lived assets and discontinued operations. Adjusted EBITDA may not be comparable to other similarly titled measures from other companies. We have included Adjusted EBITDA as a supplemental disclosure because the Company believes that it provides useful information regarding the Company's ability to service debt and to fund capital expenditures and provides investors with a helpful measure for comparing our operating performance with that of other companies.

Adjusted EBITDA, for the periods presented was as follows:

	Years ended December 31,		
(In thousands of dollars)	2004	2003	2002
Net income (loss)	(53 927)	(819 078)	(1 246 252)
Add back:			
Income (loss) from discontinued operations, net	(3 048)	5 587	215 349
Income tax expense	28 558	26 436	201 944
Other financial items, net	11 182	27 181	(42 803)
Interest expense	111 233	115 459	151 252
Income (loss) from associated companies	(5 277)	(897)	1 691
Operating profit (loss)	88 721	(645 312)	(718 819)
Other operating (income) expense	11 760	78 085	15 434
Impairment of long-lived assets	---	740 876	807 416
Depreciation and amortization	326 996	305 419	356 427
Total Adjusted EBITDA	427 477	479 068	460 458

Petroleum Geo-Services ASA

Statement of Operations

(In thousands of NOK)	Note	Years ended December 31, 2004	2003	2002
Revenue		**NOK 106 304**	NOK 200 836	NOK 386 623
Cost of sales		**8 511**	187 640	379 182
Depreciation and amortization	8	**6 442**	5 881	7 860
Selling, general and administrative costs		**234 831**	375 069	242 243
Impairment of goodwill	7	**-**	-	42
Total operating expenses		**249 784**	568 590	629 327
Operating profit (loss)		**(143 480)**	(367 754)	(242 704)
Interest expense, net	2	**(211 141)**	(182 949)	(623 764)
Impairment of shares in subsidiaries / intercompany receivable	1, 9	**(13 104)**	(5 078 291)	(8 732 432)
Other financial items, net	3	**(456 523)**	(398 873)	1 749 758
Income (loss) before income taxes		**(824 248)**	(6 027 867)	(7 849 142)
Income tax expense	4	**-**	-	313 404
Net income (loss)		**NOK (824 248)**	NOK (6 027 867)	NOK (8 162 546)

Petroleum Geo-Services ASA

Balance sheet

(In thousands of NOK)	Note	December 31, 2004	2003
ASSETS			
Long-term assets:			
Property and equipment, net	8	**NOK 37 831**	NOK 28 814
Shares in subsidiaries	1, 9	**1 851 257**	1 800 610
Intercompany receivables	1	**5 941 944**	9 416 513
Other financial assets	10	**38 786**	24 566
Total long-term assets		**7 869 818**	11 270 503
Current assets:			
Receivables		**402**	4 536
Short-term intercompany receivables		**47 981**	54 051
Other current assets		**6 267**	6 258
Restricted cash		**2 083**	3 088
Cash and cash equivalents		**452 483**	214 543
Total current assets		**509 216**	282 476
Total assets		**NOK 8 379 034**	NOK 11 552 979
LIABILITIES AND SHAREHOLDERS' EQUITY			
Shareholders' equity:			
Paid in capital:			
Common stock (20 000 000 shares, par value NOK 30)		**NOK 600 000**	NOK 600 000
Additional paid in capital		**1 104 515**	1 928 763
Total shareholders' equity	11	**1 704 515**	2 528 763
Debt:			
Pension liabilities	5	**4 873**	3 878
Other long-term debt:			
Intercompany debt	12	**502 782**	1 959 072
Long-term debt	12	**6 106 162**	6 796 152
Other long-term liabilities		**24 555**	-
Total other long-term debt		**6 633 499**	8 755 224
Current liabilities:			
Short-term debt and current portion of long-term debt	12	**-**	2 408
Short-term intercompany debt		**5 856**	29 339
Accounts payable		**14 941**	4 855
Accrued expenses	14	**15 350**	228 512
Total current liabilities		**36 147**	265 114
Total liabilities and shareholders' equity		**NOK 8 379 034**	NOK 11 552 979
Warranties	16		

Petroleum Geo-Services ASA

Statement of Cash Flows

(In thousands of NOK)	Years ended December 31, 2004	2003	2002
Cash flows from operating activities:			
Net income (loss)	**NOK (824 248)**	NOK (6 027 867)	NOK (8 162 546)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization charged to expense	**6 442**	5 881	7 860
Impairment of shares in subsidiaries / intercompany receivables	**13 104**	5 078 291	8 732 432
Items classified as investment/financing activities	**(31 174)**	41 906	(514 850)
Provision (benefit) for deferred income taxes	**-**	-	385 614
Unrealized foreign exchange (gain) loss	**449 608**	(320 571)	(4 549 177)
Changes in current assets and current liabilities	**(173 923)**	(166 810)	(142 754)
Net (increase) decrease in restricted cash	**1 005**	(1 850)	909
Other items	**11 090**	85 272	16 729
Net cash used in operating activities	**(548 096)**	(1 305 748)	(4 271 738)
Cash flows (used in) from investing activities:			
Investments in property and equipment	**(15 458)**	-	(960)
Sale of property and equipment	**-**	-	13
Sale of subsidiary	**-**	373 525	-
Investment in subsidiaries and changes in intercompany receivables	**898 195**	551 602	3 544 984
Net cash from investing activities	**882 737**	925 127	3 544 037
Cash flows (used in) povided by financing activities:			
Net increase (decrease) in bank facility	**-**	-	749 254
Repayment of long-term debt	**(33 602)**	126 058	(1 999 103)
Net increase (decrease) in short-term debt	**-**	-	2 219 982
Receipts (payments) of dividend	**31 174**	68 004	-
Net (payments) receipts under tax equalization swap contracts	**-**	-	65 696
Other items	**(24 340)**	-	-
Net cash (used in) provided by financing activities	**(26 768)**	194 062	1 035 829
Net increase (decrease) in cash and cash equivalents	**307 873**	(186 559)	308 128
Unrealized foreign exchange (gain) loss on cash and cash equivalents	**(69 933)**	(14 353)	(108 222)
Cash and cash equivalents at beginning of year	**214 543**	415 455	215 549
Cash and cash equivalents at end of year	**NOK 452 483**	NOK 214 543	NOK 415 455

Petroleum Geo-Services ASA

Notes to the Financial Statements

Note 1 Summary of Significant Accounting Policies

Petroleum Geo-Services ASA has prepared its Financial Statements in accordance with accounting principles generally accepted in Norway ("N GAAP"), and the Financial Statements are presented in Norwegian Kroner (NOK). The Company applies the same accounting policies as described in Note 2 in the notes to the consolidated financial statements, but where Petroleum Geo-Services ASA, in the financial statements, apply the Norwegian Preliminary Accounting Standard on deferred tax, where reversible temporary negative and positive differences are offset (see Note 4). Also, unrealized foreign exchange gain (loss) on long-term intercompany loans is recognized in the statement of operations.

Shares in subsidiaries (see Note 9) are presented at cost less any impairments. Based on downward adjusted estimated future cash flows in the subsidiaries, the Company recognizes impairment charges on investments in subsidiaries and intercompany receivables. In cases of improved estimated recoverable amounts, impairment charges are reversed. There is no fixed plan for repayment of long-term intercompany receivables.

Note 2 Interest Expense, Net

Interest expense, net, consist of:

	Years ended December 31,		
(In thousands of NOK)	2004	2003	2002
Interest income, external	5 278	3 058	5 667
Interest income, intercompany	659 610	749 380	768 993
Interest expense, external (a)	(633 765)	(676 404)	(1 126 387)
Interest expense, intercompany	(242 264)	(258 983)	(272 037)
Total	(211 141)	(182 949)	(623 764)

(a) Interest expense, external, in 2003 decreased significantly since no interest was paid during the Chapter 11 period (from July 29, 2003 to November 5, 2003). In addition, the restructuring reduced the total interest bearing debt.

Note 3 Other Financial Items, Net

Other financial items, net, consist of:

	Years ended December 31,		
(In thousands of NOK)	2004	2003	2002
Group contribution received	---	---	514 850
Dividends received	31 174	68 004	---
Foreign currency gain (loss)	(462 251)	(267 979)	770 883
Loss on sale of subsidiaries	---	(102 726)	---
Write-off of deferred debt costs and issue discounts	---	(94 829)	---
Other	(25 446)	(1 343)	464 025
Total	(456 523)	(398 873)	1 749 758

Note 4 Income Taxes

Reconciliation of the provision (benefit) for income taxes to taxes computed at nominal tax rate on income (loss) before income taxes:

	Years ended December 31,		
(In thousands of NOK)	2004	2003	2002
Income (loss) before income taxes	(824 248)	(6 027 867)	(7 849 142)
Norwegian statutory tax rate	28%	28%	28%
Provision (benefit) for income taxes at the statutory rate	(230 789)	(1 687 803)	(2 197 760)
Increase (reduction) in income taxes from:			
Impairment shares in subsidiaries	289 828	—	—
Permanent items	394 615	441 937	82
Deferred tax asset not recognized in balance sheet	(453 654)	1 245 866	2 511 082
Income tax expense	—	—	313 404

In accordance with the Norwegian Preliminary Accounting Standard on taxes, tax reducing and tax increasing temporary differences are offset, provided the differences can be reversed in the same period. Deferred income taxes are calculated based on the net temporary differences that exist at year-end. The Company has not recorded any net deferred tax asset due to the considerable uncertainty regarding future utilization. The temporary differences which generate the Company's deferred tax assets and liabilities are summarized as follows:

	December 31,	
(In thousands of NOK)	2004	2003
Temporary differences related to:		
Property and equipment	2 185	5 894
Pension liabilities	(1 316)	(960)
Intercompany receivables	(625 432)	(1 327 305)
Shares in subsidiaries (a)	—	(2 096 071)
Shares in affiliated companies	(97 011)	(102 398)
Tax losses carried forward	(243 237)	—
Other	(6 875)	(572)
Deferred tax liability (asset)	(971 686)	(3 521 412)
Deferred tax asset not recognised in balance sheet	971 686	3 521 412
Deferred tax liability (asset), net	—	—

(a) In 2004 the Norwegian tax law was amended so that dividend and capital gain/loss from shares are exempt from taxation. Consequently the Company's deferred tax asset related to impairment of shares in subsidiaries ceased to exist. This deferred tax asset was not recognized in the balance sheet and the change in tax law has therefore no effect on the tax expense; however the gross numbers in the table above are adjusted to reflect this change.

Note 5 Retirement Plans

The Company sponsors a defined benefit pension plan for its Norwegian employees, comprising 22 persons. This plan is funded through contributions to an insurance company, after which the insurance company undertake the responsibility to pay out the pensions. It is the Company's general practice to fund amounts to this defined benefit plan, which is sufficient to meet the applicable statutory requirements.

Net periodic pension costs:

	Years ended December 31,		
(In thousands of NOK)	2004	2003	2002
Service costs	2 661	2 282	2 061
Interest cost	995	1 062	941
Expected return on plan assets	(685)	(781)	(858)
Net amortization	209	201	11
Administration costs	87	—	—
Payroll tax	461	378	—
Net periodic pension costs	3 728	3 142	2 155

Recognized pension liabilities:

The pension liabilities have been calculated based on the underlying economic realities. The aggregate funded status on the plan and amounts recognized in the Company's balance sheet, is as follows:

	December 31,	
(In thousands of NOK)	2004	2003
Funded status	(10 205)	(5 194)
Unrecognized actuarial loss	6 067	1 863
Unrecognized prior service cost	---	44
Accrued payroll tax	(583)	(464)
Net amount recognized as accrued pension liability	(4 721)	(3 751)

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

	December 31,	
(In thousands of dollars)	2004	2003
Other financial assets	152	127
Pension liabilities	(4 873)	(3 878)
Net amount recognized as accrued pension liability	(4 721)	(3 751)

Assumptions used to determine benefit obligations:

	2004	2003	2002
Discount rates	5.3%	6.0%	6.5%
Return on plan assets	6.3%	7.0%	7.5%
Benefit increase	3.0%	3.0%	4.0%
Annual adjustment to pensions	3.0%	3.0%	3.3%

Note 6 Commitments

The Company's operating lease commitments related to the corporate administration, expires on various dates through 2010. Future minimum payments related to non-cancelable operating leases, with lease terms in excess of one year, existing at December 31, 2004 are as follows:

(In thousands of NOK)	December 31, 2004
2005	3 863
2006	3 863
2007	3 863
2008	3 863
2009	3 863
2010	3 863
Total	23 178

Rental expense for operating leases, including leases with terms of less than one year, was NOK 18,3 million, NOK 32,0 million and NOK 36,9 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Note 7 Goodwill

In 2002 the Company impaired all of its goodwill. The Company applies the same rates for depreciation as the group, and expensed amortization on goodwill of NOK 63 000 for the year ended December 31, 2002.

Note 8 Property and Equipment

Property and equipment consists of fixtures, furniture and fittings. Net book value of property and equipment is as follows:

(In thousands of NOK)	2004	2003	2002
Accumulated cost as of January 1	60 779	61 451	60 510
Additions	15 458	---	959
Disposals	(487)	(672)	(18)
Accumulated cost as of December 31	75 750	60 779	61 451
Accumulated depreciation as of January 1	31 965	26 357	20 100
Depreciation this year	6 442	5 881	6 262
Disposals	(488)	(273)	(5)
Accumulated depreciation as of December 31	37 919	31 965	26 357
Net book value	37 831	28 814	35 094

Property and equipment is depreciated over 3 to 5 years.

Note 9 Shares in Subsidiaries

Shares in subsidiaries are recognized in the Company's balance sheet at cost less any impairment:

(In thousands of NOK)	Registered office	Number of shares		Total share capital	Share-holding (a)	Par value		Book-value as of December 31, 2004 (In thousands of NOK)
PGS Geophysical AS	Oslo	1 440 000	NOK	144 000 000	100%	NOK	100	203 197
PGS Exploration (Nigeria) Ltd.	Nigeria	2 000 000	USD	2 000 000	100%	USD	1	---
PGS Reservoir AS	Oslo	1 000	NOK	100 000	100%	NOK	100	---
Petroleum Geo-Services, Inc.	Houston	1 000	USD	1 000	100%	USD	1	---
Petroleum Geo-Services (UK) Ltd.	London	222 731 726	GBP	222 731 726	100%	GBP	1	81 421
PGS Exploration (UK) Ltd.	London	44 000 000	GBP	178 353 000	24.7%	GBP	1	65 113
Seismic Exploration (Canada) Ltd.	London	7 700 000	GBP	7 701 000	100%	GBP	1	11 088
PGS Reservoir (UK) Ltd.	London	7 700 000	GBP	7 701 000	100%	GBP	1	17 219
PGS Ikdam Ltd.	London	5 100 000	GBP	5 100 100	100%	GBP	1	17 218
PGS Floating Production (UK) Ltd.	London	56 400 000	GBP	127 439 851	44.3%	GBP	1	---
PGS Processing (Angola) Ltd.	London	5 100 000	GBP	5 110 000	99.8%	GBP	1	---
Seahouse Insurance Ltd.	Bermuda	120 000	USD	120 000	100%	USD	1	8 165
Multiklient Invest AS	Oslo	100 000	NOK	10 000 000	100%	NOK	100	---
PGS Shipping AS	Oslo	4 733 975	NOK	189 359	100%	NOK	0.04	352 688
Petroleum Geo-Services Asia Pacific Pte. Ltd.	Singapore	100 000	SGD	700 032 148	100%	SGD	1	411 343
PGS Investigacào Petrolifera Limitada	Brazil	---	BRL	5 000	99%	BRL	---	---
PGS Mexicana SA de CV	Mexico	118 000 000	MXN	118 000 100	100%	MXN	1	58 359
PGS Venezuela de C.A.	Venezuela	7 000	BS	7 000 000	100%	BS	1 000	26
PGS Production AS	Trondheim	187 283 310	NOK	187 283 310	100%	NOK	1	179 611
Hara Skip AS	Oslo	1 066 016	NOK	106 601 600	100%	NOK	100	411 239
Oslo Seismic Services Ltd.	Isle of Man	1	USD	1	100%	USD	1	33 570
Pertra AS	Trondheim	1 000	NOK	1 000 000	100%	NOK	1 000	1 000
PGS Australia Pty. Ltd.	Perth	---	---	---	100%	---	---	---
Total								1 851 257

(a) Voting rights are equivalent to shareholding for all companies.

For further information on impairment of shares in subsidiaries, see Note 1.

Note 10 Other Financial Assets

Other financial asset consists of:

	December 31,	
(In thousands of NOK)	2004	2003
Deferred long-term debt costs (a)	14 156	---
Long-term receivables	24 630	24 566
Total	38 786	24 566

(a) *Deferred long-term debt costs are expensed using the effective interest method over the period loans are ooutstanding. These costs are included as part of external interest expense in the statement of operations (see Note 2).*

Note 11 Shareholders' Equity

Changes in the shareholders' equity for the years ended December 31, 2004 and 2003 are as follows:

		Paid-in capital			
(In thousands of NOK, except for share data)	Number of shares	Common stock	Share premium reserve	Other equity	Shareholders' equity
Balance at December 31, 2002	103 345 987	516 730	---	(737 465)	(220 735)
Write down of old share capital	(103 345 987)	(516 730)	---	516 730	---
Debt restructuring	20 000 000	600 000	7 076 919	1 100 446	8 777 365
Net income	---	---	(5 148 156)	(879 711)	(6 027 867)
Balance at December 31, 2003	20 000 000	600 000	1 928 763	---	2 528 763
Net income	---	---	(824 248)	---	(824 248)
Balance at December 31, 2004	20 000 000	600 000	1 104 515	---	1 704 515

As of December 31, 2004, Petroleum Geo-Services ASA had a share capital of NOK 600 million divided on a total of 20 000 000 shares, of par value NOK 30, each fully paid in. All shares have equal voting rights and are entitled to dividends. Any distribution of the Company's equity is dependent on the approval of the shareholders, and the ability to make distributions are limited by certain debt covenants and Norwegian Corporate Law (see Note 25 to the consolidated financial statements). A listing of the Company's largest shareholders is provided in Note 21 in the consolidated financial statements.

Note 12 Financial Restructuring and Debt

Financial restructuring:

On July 29, 2003, PGS voluntarily filed a 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 as well as a group of PGS' largest shareholders. PGS emerged from Chapter 11 November 5, 2003, just 100 days after filing. See Note 25 in the consolidated financial statements for further information.

Long-Term Debt

Long-term debt consists of the following:

	December 31,	
(In thousands of NOK)	2004	2003
Unsecured:		
10% Senior Notes, due 2010 ($745.9 million)	4 573 412	5 067 529
8% Senior Notes, due 2006 ($250.0 million)	1 532 750	1 698 350
Libor + 1.15% Unsecured senior term loan ($4.8 million)	---	32 681
Total debt	6 106 162	6 798 560
Less current portion	---	(2 408)
Total long-term debt	6 106 162	6 796 152

Maturities:

The Company's debt matures in the years ended December 31, 2006 and 2010 with NOK 1.5 billion ($250.0 million) and NOK 4.6 billion ($745.9 million), respectively. In May 2004, the Company repaid its loan of $4.8 million, which had an original maturity date in 2011.

Bank credit facilities:
In March 2004, the Company entered into a secured $110.0 million credit facility consisting of a $70.0 million revolving credit facility and a $40.0 million letter of credit facility. See Note 25 in the consolidated financial statements for additional information.

Long-term intercompany debt:
There is no fixed plan for repayment of long-term intercompany debt.

Covenants:
In addition to customary representations and warranties, the Company's loans agreements include various covenants. See Note 25 in the consolidated financial statements for additional information.

Subsequent events:
In February 2005 the Company established an additional overdraft facility of NOK 50 million as part of its Norwegian cash pooling system.

On March 8, 2005 the Company sent a notice of redemption relating to $175 million of its $250 million 8% Senior Notes, due 2006 ("Notes"). The Notes, in the amount of $175 million, will be redeemed April 7, 2005 at a redemption price equal to 102.00% of the principal amount of such Notes, plus accrued and unpaid interest to the redemption date.

Note 13 Financial Instruments

The Company periodically makes use of financial instruments. For a more in depth description of these instruments refer to Note 2 and Note 27 in the consolidated financial statements.

Note 14 Accrued Expenses

Accrued expenses consist of the following:

	December 31,	
(In thousands of NOK)	2004	2003
Accrued debt restructuring costs	---	172 009
Other	15 350	56 503
Total	15 350	228 512

Note 15 Salaries and Other Personnel Costs, Number of Employees, and Remuneration to the Board of Directors, Executive Officers and Auditors

Salary and social expenses that are included in cost of sales and selling, general and administrative costs consist of:

	Years ended December 31,		
(In thousands of NOK)	2004	2003	2002
Salaries	33 265	42 564	67 720
Social security	5 520	4 779	11 228
Pension	3 728	3 142	2 155
Other benefits	1 754	15 377	23 372
Total	44 267	65 862	104 475

The Company had an average of 23 employees in 2004. Average number of employees for 2003 and 2002 were 24 and 25, respectively.

Compensation to Board of Directors, CEO and other executive officers:
For a full listing our Board of Directors, CEO and other executive officers and their compensation, see Note 31 to the consolidated financial statements.

Remuneration to auditor:

Fees for audit and other services provided by the Company's auditor are as follows (exclusive VAT and inclusive out of pocket expenses):

	Years ended December 31,		
(In NOK)	2004	2003	2002
Audit fees (a)	34 261 104	42 258 889	950 000
Other financial audit	---	---	5 055 025
Total audit fees	34 261 104	42 258 889	6 005 025
Other services (b)	8 500	3 784 067	4 078 532
Total	34 269 604	46 042 956	10 083 557

(a) Fees for 2004 include fees incurred after May 31, 2004 for reaudit 2001/completion 2002 (NOK 21 919 457) and completion of audit of 2003 US GAAP including fresh start (NOK 11 041 647). The fees for 2003 include fees uncurred in 2003/2004 (until May 31, 2004) related to reaudit 2001/ completion 2002 (NOK 27 765 492)) and fresh start 2003 (NOK 13 293 397).

(b) Other services 2003 and 2002 include fees for assistance in connection with restructuring, refinancing and due-dilligence performed by banks.

Note 16 Warranties

Petroleum Geo-Services ASA provides letter of credit and related types of guarantees on behalf of subsidiaries, which normally are claimed in contractual relationships were subsidiaries are contracting parties. These guarantees are considered to be ordinary in contractual relationships, as well as in the Company's ordinary operations. See also Note 25 to the consolidated financial statements.

ERNST & YOUNG

Statsautoriserte revisorer

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To the Annual Shareholders' Meeting of
Petroleum Geo-Services ASA

Auditor's report for 2004

We have audited the annual financial statements of Petroleum Geo-Services ASA as of 31 December 2004, showing a loss of NOK 824 248 000 for the parent company and a loss of USD 53 927 000 for the Group. We have also audited the information in the Directors' report concerning the financial statements, the going concern assumption, and the proposal for the coverage of the loss. The financial statements comprise the balance sheet, the statements of operations and cash flows, the accompanying notes and the consolidated accounts. These financial statements and the Directors' report are the responsibility of the Company's Board of Directors and Chief Executive Officer. Our responsibility is to express an opinion on these financial statements and on other information according to the requirements of the Norwegian Act on Auditing and Auditors.

We conducted our audit in accordance with the Norwegian Act on Auditing and Auditors and auditing standards and practices generally accepted in Norway. Those standards and practices 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. To the extent required by law and auditing standards, an audit also comprises a review of the management of the Company's financial affairs and its accounting and internal control systems. We believe that our audit provides a reasonable basis for our opinion.

In our opinion,

- the financial statements have been prepared in accordance with law and regulations and present the financial position of the Company and of the Group as of 31 December 2004, and the results of the operations and cash flows for the year then ended, in accordance with accounting standards, principles and practices generally accepted in Norway
- the Company's management has fulfilled its duty to properly register and document the accounting information as required by law and accounting standards, principles and practices generally accepted in Norway
- the information in the Directors' report concerning the financial statements, the going concern assumption, and the proposal for the coverage of the loss is consistent with the financial statements and complies with law and regulations.

Oslo, 31 March 2005
ERNST & YOUNG AS

Jan Egil Haga
State Authorised Public Accountant (Norway)

Note: The translation to English has been prepared for information purposes only.

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