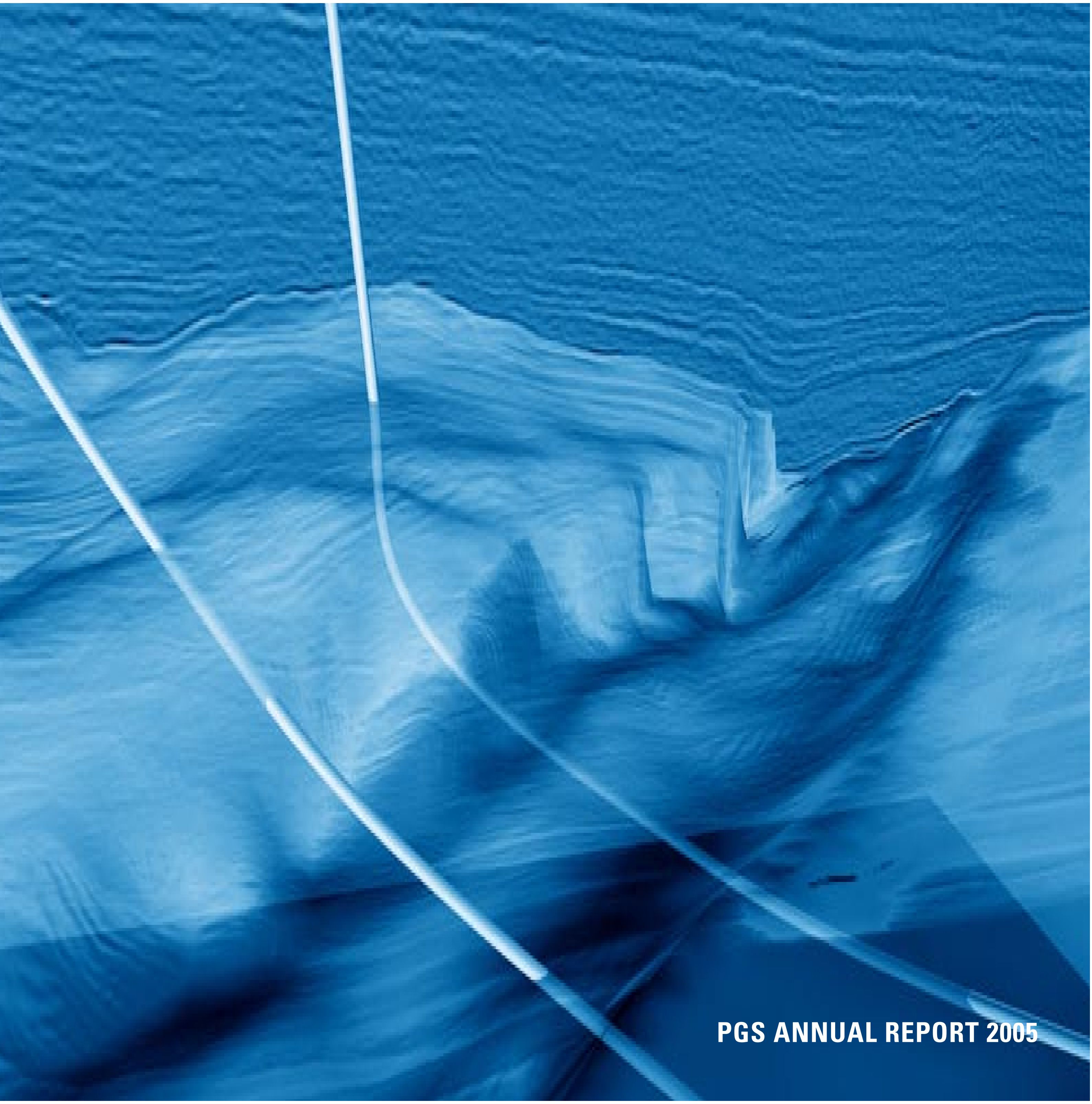
POSITIONING FOR GROWTH

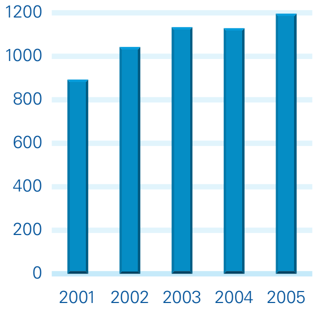


PGS ANNUAL REPORT 2005

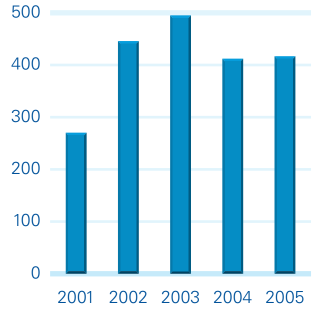
PETROLEUM GEO-SERVICES

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

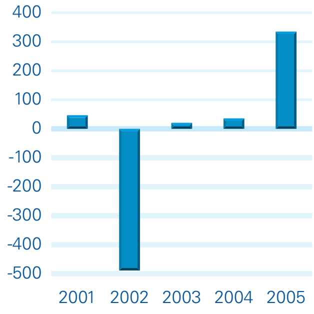
Revenues
In million of dollars (US GAAP)



Adjusted EBITDA
In million of dollars (US GAAP)



Operating profit
In million of dollars (US GAAP)



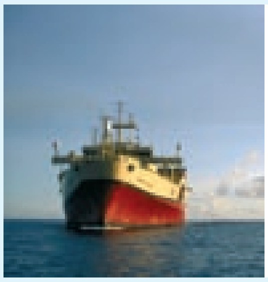
BUSINES

CONTENTS

FINANCIAL CALENDAR

Q1 2006 Earnings Release	May 4, 2006
Annual General Meeting of Shareholders 2006	June 14, 2006
Q2 2006 Earnings Release	July 27, 2006
Q3 2006 Earnings Release	October 26, 2006

MARINE GEOPHYSICAL



KEY FIGURES

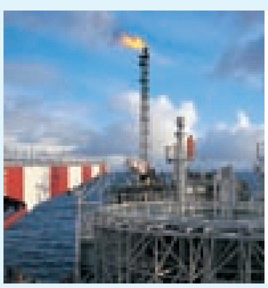
In million of dollars (US GAAP)	**2005**	2004	2003	2002
Revenues	**724.7**	570.8	599.5	592.6
Operating profit	**154.5**	(35.0)	(55.3)	(188.5)
Total assets	**797.3**	795.1	959.3	1 300.0
Head count	**1 192**	1 115	1 143	1 356

ONSHORE

KEY FIGURES

In million of dollars (US GAAP)	**2005**	2004	2003	2002
Revenues	**152.5**	133.2	150.4	118.7
Operating profit	**(9.8)**	(4.5)	16.1	(21.8)
Total assets	**98.8**	90.5	117.4	119.5
Head count	**3 237**	1 011	1 479	1 828

PRODUCTION

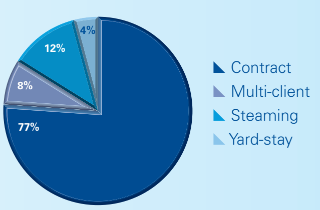


KEY FIGURES

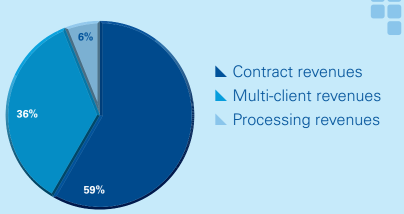
In million of dollars (US GAAP)	**2005**	2004	2003	2002
Revenues	**280.7**	298.2	295.3	306.6
Operating profit	**43.5**	77.8	78.4	(246.6)
Total assets	**676.3**	710.5	790.3	1 168.6
Head count	**512**	501	515	520

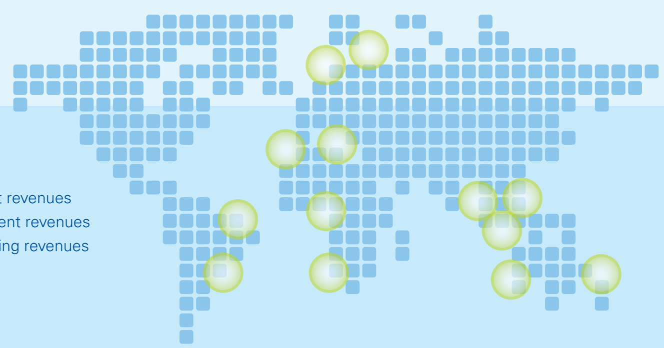
S AREAS

Vessel utilization 2005
In per cent of total streamer months

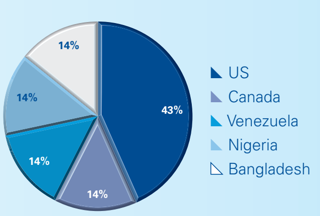


Revenues 2005
Split of total revenues



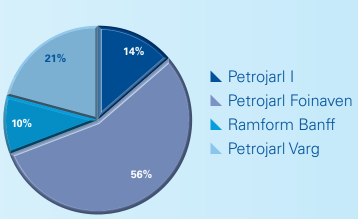


Geographical spread of crew
Per December 31 2005

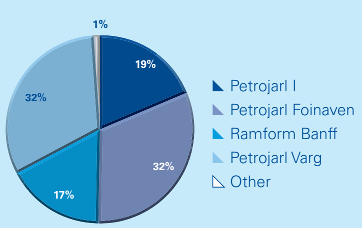


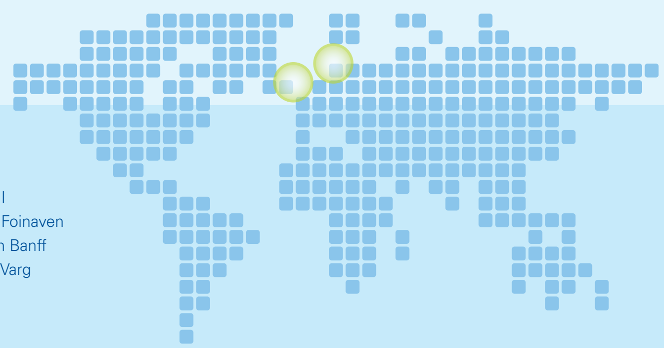
Revenues 2005
Split of total revenues

Oil production
From the four FPSOs



Revenues 2005
From the four FPSOs





The information in this annual report is updated as of December 31, 2005, unless otherwise stated.

Key Financial Figures

In million of dollars (US GAAP)	**2005**	2004	2003	2002
Revenues	**1 196.3**	1 129.5	1 134.2	1 043.2
Adjusted EBITDA	**416.9**	412.2	495.2	445.9
Operating profit	**335.4**	35.7	20.5	(488.6)
Net income	**112.6**	(134.7)	547.0	(1 174.7)
EPS	**1.88**	(2.25)	9.12	(19.58)
DPS	**-**	-	-	-
Cashflow from operations	**279.1**	282.4	227.1	294.6
Capex	**(90.5)**	(148.4)	(58.1)	(56.7)
Multi-client investments	**(55.7)**	(41.1)	(90.6)	(151.6)
Total assets	**1 717.6**	1 852.2	1 997.4	2 839.7
Multi-client library	**146.2**	244.7	408.0	583.9
Cash	**146.0**	168.4	156.4	122.9
Shareholders' equity	**329.3**	222.9	353.6	(192.3)
Net interest bearing debt	**828.7**	995.3	1 077.0	2 316.7
Head count (year end)	**5 130**	2 899	3 377	4 003
LTIF	**0.29**	0.40	0.26	0.66
TRCF	**2.19**	2.33	3.00	4.41

Pro forma information [1)]

	2005	2004	2003	2002
Revenues ex Pertra	**1 170.1**	1 017.5	1 062.4	1 032.4
Adjusted EBITDA ex Pertra	**410.3**	347.0	449.6	442.4
Operating profit ex Pertra	**177.7**	9.5	6.5	(479.4)
Capex ex Pertra	**(90.4)**	(63.4)	(23.9)	(48.5)
Total assets ex Pertra	**1 717.6**	1 731.5	1 930.3	2 764.1
Head count ex Pertra	**5 130**	2 883	3 372	3 997

1) PGS sold its subsidiary Pertra March 1st 2005

Highlights 2005:

- Further improvement of the strong safety performance
- Strong cash flow and significant debt reduction
- Significantly improved operating profit margins for marine contract seismic
- Marine multi-client sales increased by 8%, despite three years of low multi-client investments
- Sale of oil and gas subsidiary Pertra
- The majority of debt repaid or refinanced to increase operating flexibility and reduce finance costs

Additional highlights – January through April 2006

- Acquisition of shuttle tanker *Rita Knutsen* for possible FPSO conversion
- Proposed strategic joint venture between PGS Production and Teekay Shipping Corporation to develop new FPSO projects
- Announcement of a project to build a new and enhanced Ramform seismic vessel
- Proposed plan to demerge the production business under the name Petrojarl ASA
- Demerger plan approved by the Extraordinay General Meeting April 28. Listing of Petrojarl planned on or about June 30.

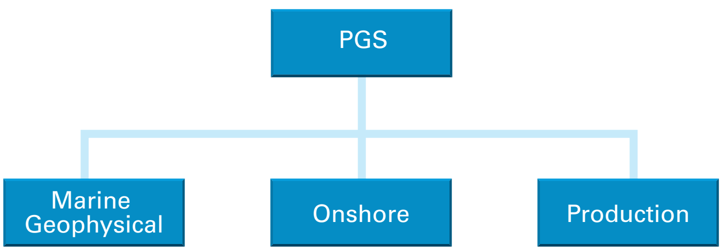
MARKET LEADERSHIP AND OPERATIONAL EXCELLENCE

Petroleum Geo-Services is a technologically focused oilfield service company involved in providing geophysical services worldwide and floating production services in the North Sea.

PGS was established in 1991 with the merger of Geoteam and Nopec. PGS was among the leading companies worldwide to develop and market 3D seismic. In 1998 PGS acquired Golar-Nor, the owner of the FPSOs *Petrojarl I* and *Petrojarl Foinaven*. We added later *Ramform Banff* and *Petrojarl Varg* to our fleet. In 2002 we established the exploration and production company Pertra.

In March 2005, Pertra was sold to Talisman and PGS became a dedicated oil-services company. During 2005, substantially all of our debt was either repaid or refinanced.

Today, PGS operates through its three business units, Marine Geophysical, Onshore and Production. The principal offices are at Lysaker, Norway. We are represented in 25 different countries with larger regional offices in London, Houston and Singapore. PGS had 5,130 full time employees at year end 2005. Our revenues for 2005 were approximately $1.2 billion.



MARINE GEOPHYSICAL AND ONSHORE

These two business units provide a broad range of geophysical and reservoir services globally, including seismic data acquisition, processing and interpretation and field evaluation. Our geophysical business is one of the world's leading operators in marine seismic, with a global market share of approximately 30 percent. In the market for onshore seismic services, we are one of the larger operators worldwide.

PRODUCTION

PGS Production is a pioneer within floating production. We own and operate four harsh environment floating production, storage and offloading ("FPSO") units. This is the largest and most advanced fleet in the North Sea. We are also looking for growth opportunities beyond the North Sea.

Our Board of Directors has signed a demerger plan to separate the geophysical and production businesses. The plan was approved by the Extraordinary General Meeting on April 28. As a result of the demerger, the PGS shares will be split into shares of two separate companies.

POSITIONING FOR GROWTH

Business priorities in 2006

PGS intends to create shareholder value through establishing the geophysical and production businesses as separate and focused companies. The separation plan was approved by the extraordinary general meeting on April 28, and is expected to be completed on or about June 30, 2006. After the separation, the geophysical business will continue in PGS, while the production business will be discontinued as part of PGS and continued through the company Petrojarl ASA. Our short term main priority is to successfully complete the separation and position both companies for growth.

The focus on health, safety and environment performance will continue. We will also strengthen internal controls and continue to focus on corporate governance and human resource capabilities.

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

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

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

MARKET OUTLOOK 2006

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

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

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

Marine Geophysical

- Marine 3D industry seismic fleet at full capacity utilization with our streamer contract operating profit margins expected to improve by more than 10 percentage points compared to full year 2005
- Multi-client late sales expected to be lower than 2005 as a result of low level of investments in recent years
- Cash investments in multi-client library expected to double from an investment of $46 million in 2005, with continued high pre-funding levels

Onshore

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

Production

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

Positioning for Growth

During the last year we have taken decisive steps to clarify PGS' strategic direction and to position the company for renewed growth. It has been a year of substantial value creation for our shareholders.

Early last year we exited the E&P business. The divestment of our E&P subsidiary Pertra did not reflect a lack of belief in the future of that business, but a recognition that PGS could not effectively grow simulteanously both as an oil services company and as an E&P company. The industry rationale was not there – and the financial capability was not there. We achieved an excellent price for Pertra and we used the proceeds to further deleverage the Group.

Deleveraging and strong cash flow delivery were instrumental in achieving a successful and full refinancing of the Group late last year. The refinancing has since allowed us to fast and effectively target, explore and pursue a separation of the Group into two stand alone entities: PGS – the Geophysical Company, and Petrojarl – the FPSO company. 28 April 2006 our extraordinary general meeting approved the plans for separation and demerger. On or about June 30, 2006, Petrojarl is expected to become a listed company on the Oslo Stock Exchange through a combined offering and demerger.

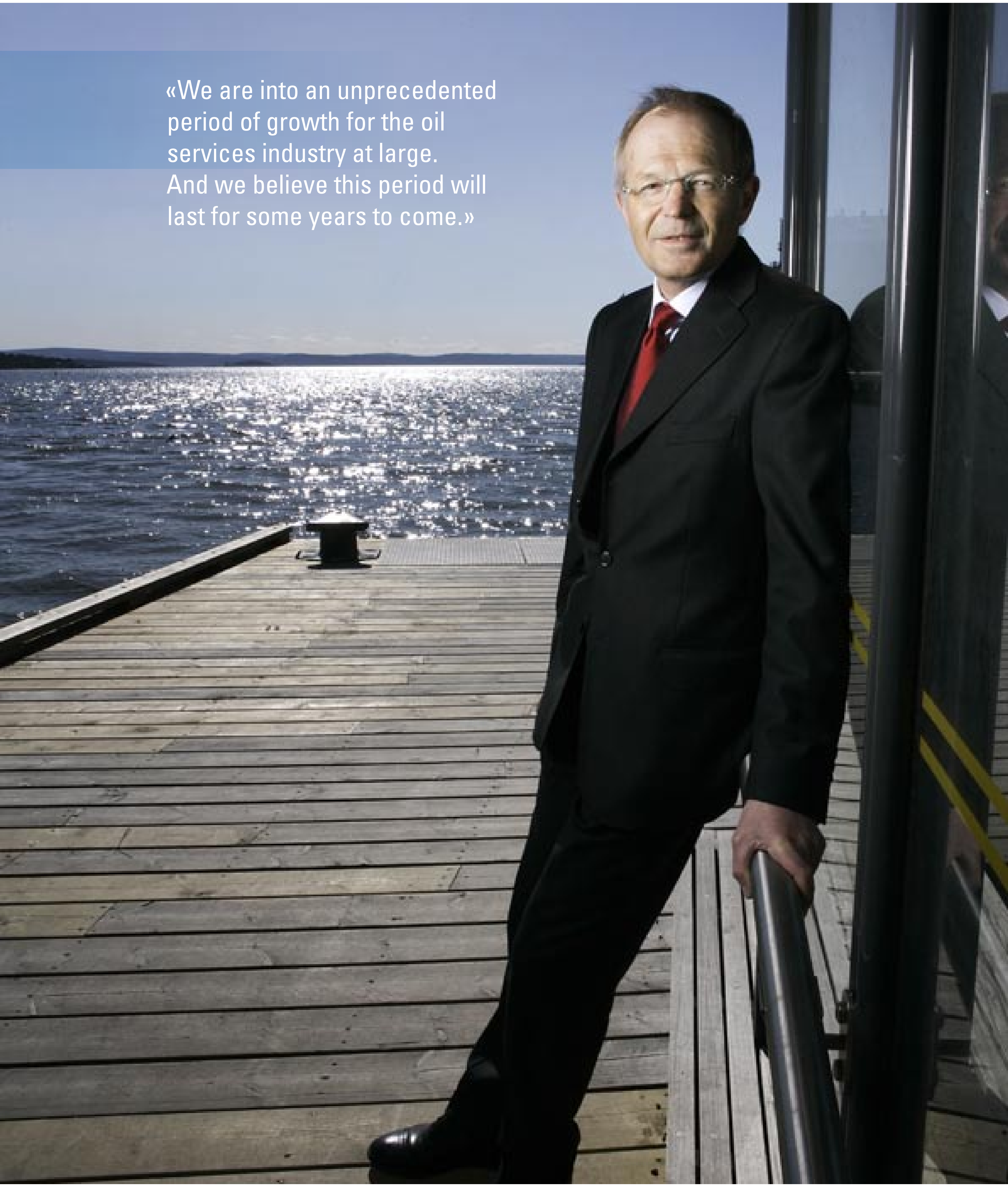
The separation of PGS into two listed companies is about moving on the offensive and taking full advantage of the growth capabilities of each entity. We are into an unprecedented period of growth for the oil-services industry at large. And we believe this period will last for some years to come. Demand is driven by rising investments from international and national oil companies to rebuild their hydrocarbon reserves and enhance production capacities. Through our competence base and asset base, we are uniquely positioned to benefit from these trends short-term, medium-term and longer-term.

Petrojarl is targeting growth opportunities both inside and outside its current area of strength – the North Sea. We believe the planned joint-venture with Teekay Shipping Corporation will leverage our growth capabilities further.

Increasing demand for seismic and more advanced seismics, will offer PGS the Geophysical company ample room for expansion. We continue to build on the Ramform technologies to further enhance our edge in productivity and high definition seismics.

PGS is moving ahead with a clearer image.

Svein Rennemo
President and CEO



«We are into an unprecedented period of growth for the oil services industry at large. And we believe this period will last for some years to come.»

INITIATIVE AND INNOVATION

With the ability to tow up to 20 streamers per vessel, our marine seismic fleet is the most advanced in the world.

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 them manage the production of reservoirs.

PGS' Marine Geophysical streamer fleet consists of:

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

In addition we have one 2D vessel. We are among the worlds largest companies acquiring marine seismic data and own the largest international marine multi-client library. We also have a data processing activity.

RAMFORM FLEET

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

Our six 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.

Our Ramform seismic vessels have demonstrated unmatched towing capabilities, efficiencies, flexibility, along with industry leading HSE performance.

2005 OPERATIONAL PERFORMANCE

Marine Geophysical had revenues of $724.7 million in 2005, an increase of 27% compared with 2004. Revenues from contract seismic acquisition increased by 42% to $424.2 million, primarily due to an improvement in the market for marine contract seismic and strong operating performance. Multi-client late sales were $218.8 million, up 8% compared to 2004. The strongest performing regions for multi-client sales were West Africa, Gulf of Mexico and Europe.

Pre-funding as a percentage of cash investments in multi-client data decreased to 87% in 2005 compared to 99% in 2004. In 2005, we used 91% of our active vessel time acquiring contract seismic, and 9% acquiring multi-client seismic, compared to approximately 88% and 12%, respectively, in 2004. Over time we expect to utilize 20% of our active vessel time for multi-client acquisition.

At December 31, 2005, our order backlog in Marine Geophysical was $365 million compared with $170 million at December 31, 2004.

2005 HSE PERFORMANCE

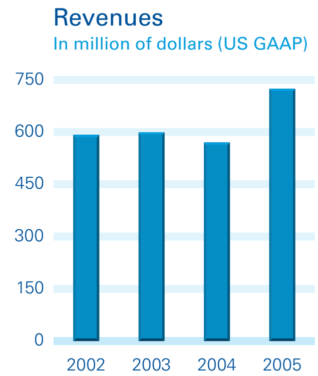
Marine Geophysical had a Lost Time Incidents Frequency (LTIF) of 0.33 per million man hours in 2005, compared to a LTIF of 0.63 in 2004, and a Total Recordable Case Frequency (TRCF) of 1.32 per million man hours, compared to a 1.42 in 2004.

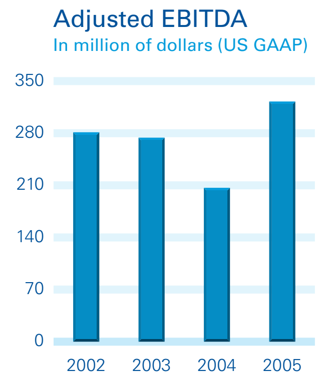
MARKET AND MARKET POSITION

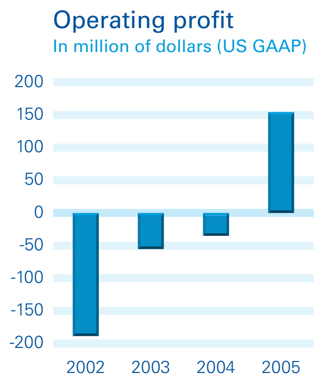
PGS Marine Geophysical has a market share of approximately 30% measured in acquired square kilometer 3D seismic. Our main competitors are WesternGeco, Compagnie Generale de Geophysique (CGG) and Veritas DGC.

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.





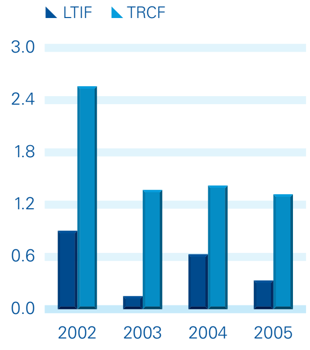


KEY FIGURES MARINE GEOPHYSICAL

In million of dollar (US GAAP)	**2005**	2004	2003	2002
Revenues	**724.7**	570.8	599.5	592.6
Cost of sales	**(402.1)**	(364.1)	(325.4)	(311.3)
Adjusted EBITDA	**322.6**	206.7	274.1	281.3
Depreciation and amortization	**(172.3)**	(241.7)	(230.6)	(247.9)
Segment operating profit	**150.2**	(35.0)	43.6	33.4
Other operating income (expense)	**8.8**	-	(9.3)	(1.3)
Impairment	**(4.6)**	-	(89.6)	(220.6)
Operating profit	**154.5**	(35.0)	(55.3)	(188.5)
Total assets	**797.3**	795.1	959.3	1 300.0
Backlog	**365**	170	105	93
Head count	**1 192**	1 115	1 143	1 356

HSE key figures

Per million work hours



DATA PROCESSING

Processing the seismic data with our 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; and
- the chances of maximizing total reserve recovery at the production stage.

Through the seismic data processing operations we provide:

- 2D and 3D data processing of onshore and marine seismic surveys;
- onboard (vessel) seismic data processing for reduced delivery times and enhanced real-time quality control for data that 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; and
- other specialized signal enhancement techniques.

Backed by a strong Research and Development organization we have developed our 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 December 31, 2005 we operated 15 land-based seismic data processing centers, with the largest centers being located in Houston, London and Perth.

MEGASURVEY

The unique MegaSurvey product from PGS consists of huge volumes of seismic data and is a method to conduct detailed prospectivity studies on a regional scale. PGS has a MegaSurvey in the North Sea and several new MegaSurveys are in development in active regions around the world.

HD3D℠

HD3D℠ seismic is a premium seismic data product. 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.

GOALS AND STRATEGIES

In Marine Geophysical we aim to capture the value from our strong operating platform and expected market upturn by using our productivity leadership, increasing our streamer count, maximizing our capacity utilization and bid to capture the value of our services in a strong market.

We will focus on value added products and services such as HD3D℠, MultiAzimuth and MegaSurveys, while increasing our multi-client investments, including new multi-client investments in Gulf of Mexico.

In the long term we aim to sustain our market share and explore segment focused or broad based restructuring initiatives at the appropriate time.

OUTLOOK

We expect Marine Geophysical to improve its streamer contract operating profit margin by more than 10 percentage points in 2006 compared to 2005, when the margin was above 20%. Multi-client late sales are expected to be lower in 2006 than the level from 2005 of $218.8 million. The multi-client investments in 2006 are expected to double compared to 2005, when they were $46.2 million. The capital expenditure in Marine Geophysical in 2006, excluding multi-client investments, is expected to be between $90 and $100 million, up from $72.2 million in 2005. The increase in the capital expenditures is primarily related to the streamer expansion and replacement program.

In addition we expect payments of approximately $55 million in 2006 in relation to our new third generation Ramform seismic vessel.

TECHNICAL SPECIFICATIONS SEISMIC FLEET

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

1) *We have terminated the charter for Bergen Surveyor and the vessel was returned to its owner in the first quarter of 2006.*
2) *Falcon Explorer was converted to a 2D vessel and Ocean Explorer was converted to a six streamer 3D vessel in the first quarter of 2006.*

In March 2006, we announced that we intended to build a new third generation Ramform seismic vessel at Aker Yards, Langsten, Norway. We currently expect delivery in the first quarter 2008.

WORDS & DEFINITIONS:

SEISMIC DATA

Seismic data is used by oil and natural gas companies to help them find oil and gas, to determine the size and structure of known reservoirs and to help them manage the production of reservoirs.

ACQUISITION TECHNOLOGIES

2 dimensional (2D)
– data 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^{SM})
– 3D data with significantly higher resolution and quality than ordinary seismic. HD3D^{SM} allows for improved resolution of the subsurface and higher quality images of the reservoirs.

4 Component (4C)
– also referred to as seafloor seismic or ocean bottom seismic. The recording cables are placed directly on the ocean floor. This method provides more information about the subsurface.

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

MultiAzimuth
– By acquiring multiple 3D surveys in several directions, illumination of the geology is improved, especially beneath complex salt bodies where conventional seismic leaves shadows.

CONTRACT OPERATIONS

In contract operations, clients direct the scope and extent of the survey and retain ownership of the data obtained.

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 exclusive contract 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, we assume the risk that future sales may not cover the cost of acquiring and processing such seismic data. Obtaining pre-funding for a portion of these costs reduces this risk.

PRE-FUNDING

In multi-client operations, PGS sells early licenses of data prior to project completion, referred to as pre-funding.

LATE SALES

All further licenses other than pre-funding (se above) of multi-client data are referred to as late sales.

ACTIVE TENDERS

Tendering activity in the marine 3D contract seismic market improved strongly in 2005. From December 2004 to December 2005, the total amount of active tenders for marine 3D contract seismic increased over 100%, according to internal estimates. At the end of 2005 active tenders for marine 3D contract seismic stood at approximately $900 million.

WEIGHTED AVERAGE BACKLOG MAJOR CONTRACTORS

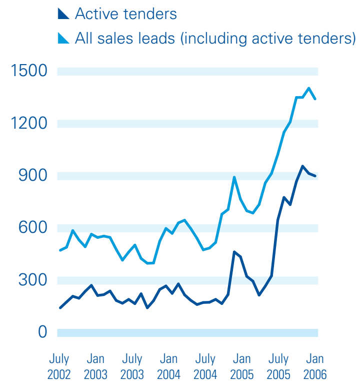
In 2005 the visibility for the seismic companies greatly improved. At the start of the year, each major seismic company had on average a little over four months of work for each of its vessels. At the end of 2005, the average backlog for each seismic vessel was estimated to be near six months, according to internal estimates.

TOTAL STREAMERS WORLDWIDE

We expect the number of used streamers in the global seismic fleet to increase by more than 15% from 2005 to 2006 and by approximately 30% from 2005 to 2007.

Sales leads and tendering

In million of dollars



Source: PGS internal estimates

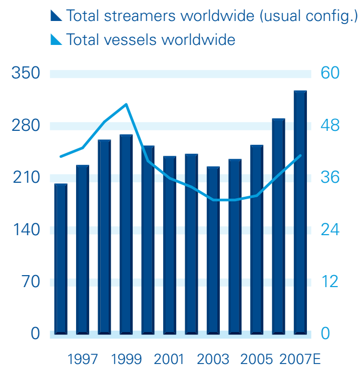
Weighted average backlog

Major contractors (days per vessel)

Source: PGS internal estimates

Total streamers worldwide

In actual numbers



Source: PGS internal estimates

VESSEL UTILIZATION

PGS has since 2002 increased the amount of vessel capacity the Company uses to acquire contract seismic, and reduced the multi-client component. In 2005, PGS used 77% of its capacity acquiring contract seismic, while 8% was used to acquire multi-client seismic. This corresponds to a use of 9% of the active vessel time in multi-client seismic. PGS targets to use 20% of its active vessel time acquiring multi-client seismic over time.

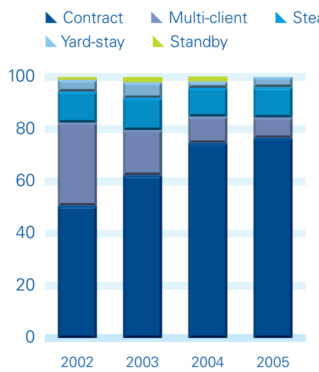
DEMAND FOR SEISMIC

Based upon internal estimates, approximately 190 000 square kilometers of 3D seismic was aquired worldwide in 2005, of which multi-client seismic represented approximately 25%. In 2006, we estimate that there is demand for almost 280 000 square kilometer of 3D seismic. That is nearly 30% more than what we estimate the global 3D seismic fleet can acquire.

MULTI-CLIENT LIBRARY

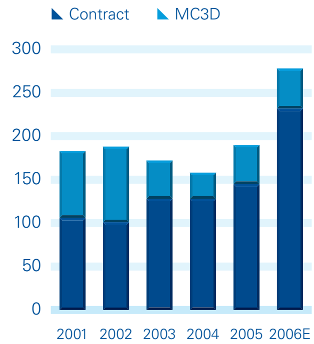
PGS has the largest multi-client library outside Gulf of Mexico in the industry. Measuring 323 450 square kilometers in total, the library is evenly distributed between all major regions worldwide and provides a broad opportunity in light of the increased demand for multi-client 3D data.

Vessel utilization



Demand for seismic

In sqkm

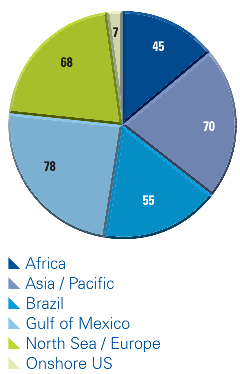


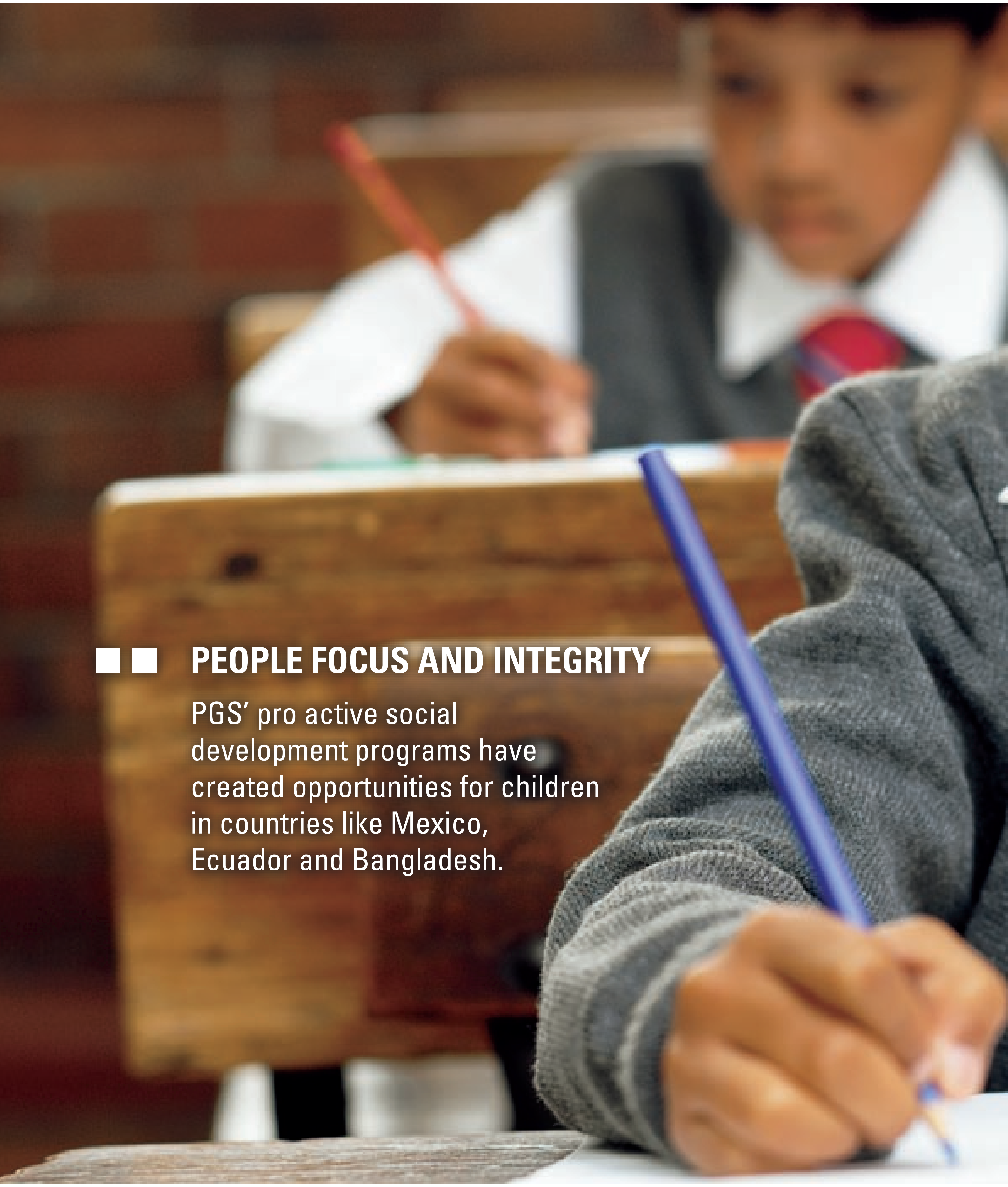
2001 to 2005 shows activity while 2006 shows estimated demand

Source: PGS internal estimates

PGS multi-client library 2005

In '000 sqkm





PEOPLE FOCUS AND INTEGRITY

PGS' pro active social development programs have created opportunities for children in countries like Mexico, Ecuador and Bangladesh.

ONSHORE

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

We conduct contract onshore and transition zone seismic acquisition throughout the world and operated between five and nine crews in 2005. We also have our own onshore multi-client library, which is located entirely in the United States. Our 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.

We have demonstrated market leading seismic service performance operating seismic crews in the terrain types desert, arctic, jungle and swamp, highland and mountaintop, and transition zone.

As of December 31, 2005, we had seven onshore crews conducting activities in the United States, Canada, Venezuela, Nigeria and Bangladesh.

2005 OPERATIONAL PERFORMANCE

Onshore revenues for 2005 increased by 15% to $152.5 million compared with 2004. The operating loss in Onshore was $9.8 million, compared to an operating loss of $4.5 million in 2004. The performance in 2005 was affected by mobilization costs on new projects in Nigeria and Libya.

At December 31, 2005, our order backlog for onshore seismic was $137 million compared with $66 million at December 31, 2004.

2005 HSE PERFORMANCE

Onshore operations recorded a Lost Time Incidents Frequency (LTIF) of 0.33 incidents per million man hours and a Total Recordable Case Frequency (TRCF) of 2.68 incidents per million man hours during the year, compared to a LTIF and TRCF of 0.36 and 2.85, respectively, in 2004.

COMPETITIVE ADVANTAGE

Equipping our highly experienced personnel with fully compatible, state of the art recording electronics allows us to deploy on average more channels per crew than other companies. We offer 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 data quality.

Proactive social development programs have created a competitive advantage in countries like Bangladesh, Bolivia, Ecuador and Mexico. We work to establish a good relationship and communication with the local population in the areas where we work and strive to ensure that the jobs go to the people in the area. We also sponsor educational needs among other efforts to promote social development.

MARKET AND MARKET POSITION

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

Onshore Market Perspectives

We expect an improvement in the onshore seismic markets in Canada, US, North Africa and West Africa in 2006 compared to 2005. In the Caspian and South East Asia we expect to see a flat development, while the Arctic, Latin America and Middle East are expected to show a downturn in activity in 2006.

The focus markets for PGS Onshore in 2006 are estimated to have a total value of approximately $2.3 billion, with the largest ones being North America and North Africa.

Onshore Multi-Client Library

PGS Onshore 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. The onshore multi-client library has a size of 7,050 square kilometre and is included in our multi-client library.

GOALS AND STRATEGIES

Onshore will continue its focused market approach and financial discipline going forward. We will use our operational expertise and our standardized equipment to improve our financial performance. We will continue our social responsibility program and effort to promote HD3D℠ in the onshore market.

OUTLOOK

We expect revenues and operating profit in PGS Onshore in 2006 to be significantly above 2005 levels. Cash investments in the multi-client library are expected to more than double form an investment of $8 million in 2005. Capital expenditures in onshore is expected to be approximately $10 million.

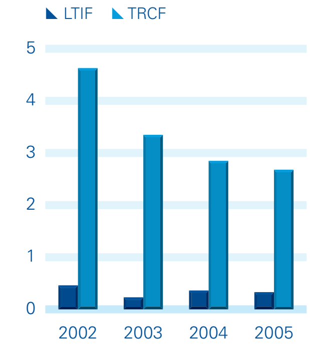
KEY FIGURES ONSHORE

In million of dollars (US GAAP)	**2005**	2004	2003	2002
Revenues	**152.5**	133.2	150.4	118.7
Cost of sales	**(130.7)**	(97.9)	(93.2)	(103.5)
Adjusted EBITDA	**21.9**	35.3	57.2	15.2
Depreciation and amortization	**(31.7)**	(39.9)	(35.7)	(28.4)
Segment operating profit	**(9.8)**	(4.5)	21.5	(13.2)
Other operating income (expense)	**-**	-	(0.3)	(2.6)
Impairment	**-**	-	(5.1)	(5.9)
Operating profit	**(9.8)**	(4.5)	16.1	(21.8)
Total assets	**98.8**	90.5	117.4	119.5
Backlog	**137**	66	111	-
Head count	**3 237** 1)	1 011	1 479	1 828

1) The increase in the number of our Onshore employees in 2005 was primarily due to hiring of local workers to staff sesmic crews in connection with a project in Bangladesh

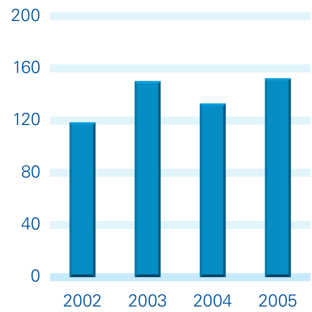
HSE key figures

Per million work hours



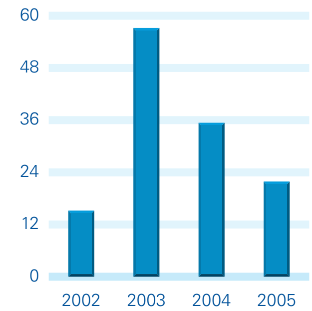
Revenues

In million of dollars (US GAAP)



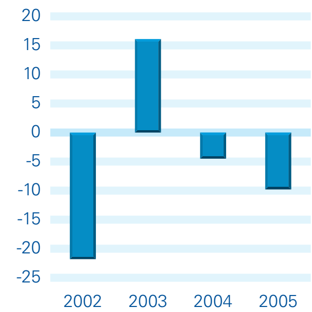
Adjusted EBITDA

In million of dollars (US GAAP)



Operating profit

In million of dollars (US GAAP)



DELIVERY AND RELIABILITY

We are able to operate FPSO vessels in one of the most demanding environments in the world. Petrojarl Foinaven has as an example produced oil in North Atlantic storms with 20 meter high waves.

PRODUCTION

PGS is the largest contractor operator of FPSO vessels in the North Sea, measured by production capacity and number of vessels.

OUR PRODUCTION BUSINESS

Through PGS Production, we own and operate 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. We have a long, proven track record in operating FPSOs in one of the harshest environments in the world.

An FPSO is a ship-based 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. We operate two shuttle tankers: *Petronordic* and *Petroatlantic*, and one storage tanker, *Nordic Apollo*.

PGS Production has its head office in Trondheim, Norway.

On March 27, 2006, our Board of Directors resolved to sign a demerger plan to separate our geophysical and production businesses into two independently listed companies. The production business has been named Petrojarl ASA. The dermerger plan was approved by the extraordinary general meeting April 28. The shares in Petrojarl are planned to be listed on Oslo Stock Exchange on or about June 30, 2006.

Petrojarl ASA

2005 OPERATIONAL PERFORMANCE

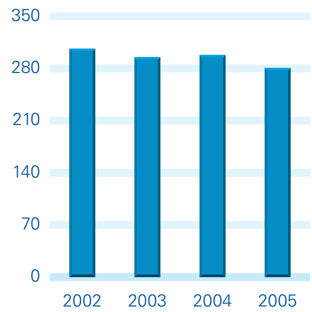
PGS Production revenues for 2005 amounted to $280.7 million, a decrease of 6% compared to 2004, primarily due to lower production on the Foinaven and Glitne field.

The operating profit fell to $43.5 million dollar compared to $77.8 million in 2004.

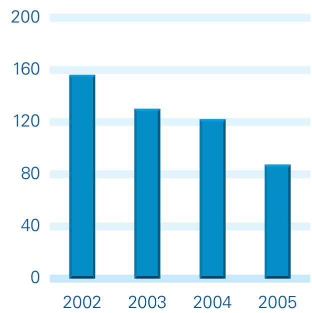
2005 HSE PERFORMANCE

PGS Production achieved excellent HSE performance in 2005, with no reported Lost Time Incidents. For 2005 the Lost Time Incident Frequency (LTIF) was 0 per million man hours, unchanged from 2004. The Total Recordable Case Frequency (TRCF) was 2.61, up from 1.70 in 2004.

Revenues
In million of dollars (US GAAP)



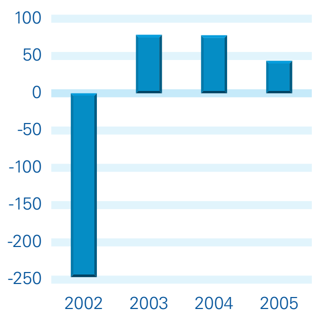
Adjusted EBITDA
In million of dollars (US GAAP)



KEY FIGURES PRODUCTION

In million of dollars (US GAAP)	**2005**	2004	2003	2002
Revenues	**280.7**	298.2	295.3	306.6
Cost of sales	**(193.1)**	(175.9)	(165.0)	(150.3)
Adjusted EBITDA	**87.6**	122.3	130.3	156.3
Depreciation and amortization	**(44.1)**	(44.6)	(51.5)	(71.0)
Segment operation profit	**43.5**	77.8	78.8	85.3
Other operating income (expense)	**-**	-	-	-
Impairment	**-**	-	(0.3)	(332.0)
Operating profit	**43.5**	77.8	78.4	(246.6)
Total assets	**676.3**	710.5	790.3	1 168.6
Head count	**512**	501	515	520

Operating profit
In million of dollars (US GAAP)



TECHNICAL SPECIFICATIONS FPSOS

	Petrojarl I	Petrojarl Foinaven	Petrojarl Varg	Ramform Banff	Ikdam
Length	209 m	250 m	214 m	120 m	292 m
Max beam	32 m	34 m	38 m	53 m	41 m
Depth	18 m	19 m	22 m	16.5 m	
Draught	12 m	13 m	16 m	11.5 m	17 m
Oil production	47 000 BOPD	140 000 BOPD	57 000 BOPD	95 000 BOPD	30 000 BOPD
Water injection	52 000 BWPD	165 000 BWPD	100 000 BWPD	90 000 BWPD	52 000 BWPD
Gas handling	20 mmscfd	100 mmscfd	53 mmscfd	83 mmscfd	3 mmscfd
Storage capacity	180 000 bbls	280 000 bbls	420 000 bbls	120 000 bbls	790 000 bbls
Risers	8	15	10	10	3
Built	1986	1996	1999	1998	1971/2001
Ownership	98.5%	99.25%	100%	100%	40%

MARKET AND MARKET POSITION

The demand for FPSOs is highly dependent on specific oil and gas development projects for small to medium sized oil fields. As of December 31, 2005, we operated four harsh environment FPSOs in the North Sea. Our ambition is to double our fleet by 2010. This growth could come from areas beyond the North Sea.

In January 2006, we purchased the shuttle tanker *Rita Knutsen* for a possible FPSO conversion. In February 2006, we announced a proposed joint venture with Teekay Shipping Corporation to develop new FPSO projects.

MAIN GROWTH MARKETS FOR FPSO

Third party surveys estimate that there will be awarded more than 20 new FPSO contracts in the next three years. The biggest growth in the years to come is expected to come from South America and West Africa.

GOALS AND STRATEGIES

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

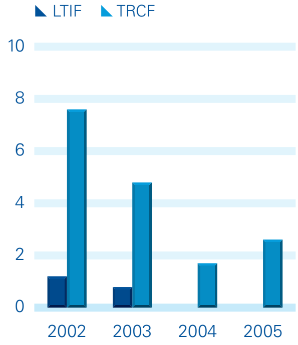
We believe opportunities exist in the North Sea, particularly on the Norwegian Continental Shelf where we currently operate two vessels, to redeploy our FPSO vessels when our existing FPSO contracts terminate. We also intend to continue to evaluate redeployment opportunities in other regions.

OUTLOOK

We expect revenues from our production business in 2006 to be slightly lower than full year 2005. Operating expenses in 2006, including maintenance, is expected to be broadly in line with 2005. Capital expenditures in Production on our existing vessels are expected to continue at a low level. A conversion of *Rita Knutsen* into a FPSO would require a substantial capital expenditure and depend on the particular project.

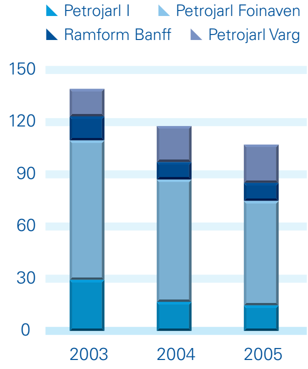
HSE key figures

Per million work hours



Oil production

In thousands of barrels per day



WORDS & DEFINITIONS:

FPSO

An FPSO (floating production, storage and offloading unit) is a ship-based mobile production unit that produces, processes, stores and offloads oil. The units can also re-inject 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.

FLEXIBLE RISER

The hydrocarbons treated on an FPSO are produced through wells that are located on the seabed. Untreated liquids are brought to the surface via subsea equipment on the sea floor including valves at the well (a "Christmas tree"), a manifold to connect several wells together into one flowline, which is then linked to the vessel. These pipelines must pass from the seabed to the floating facility at the surface - and are called "risers". They must be flexible to accommodate the heaving motion of the vessel above, and be very resistant to fatigue.

TURRET

In the North Sea where weather conditions can be extreme, most vessels have a central mooring arrangement located within the hull in a "turret", that allows them to rotate freely around the point of mooring in response to shifting weather direction. This is known as "weathervaning" and allows the vessel's bow always to point into the prevailing wind and currents, minimizing the impact of nature's forces. Often thruster systems are also used to supplement the station-keeping and control vessel heading.

PETROJARL I

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 beyond 2008.

MAIN TERMS AS OF DECEMBER 31, 2005

Rates

Variable rate	$3.50 per barrel produced
Fixed rate	$12 750 per day. Up to $5 000 per day for water injection
Minimum rate	USD 58 500 per day
Maximum rate	USD 108 500 per day
Firm rate	NOK 475 585 per day for operating expenses (approximately USD 70 262)

Termination clauses

From Operator	6 months
From PGS Production	3 months if minimum rate of $58,500 + firm rate has been paid in 90 out of 120 days. Operator may in such case increase tariff by $1 per barrel
Expected end of contract	Beyond 2008

PETROJARL FOINAVEN

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. 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.

MAIN TERMS AS OF DECEMBER 31, 2005

Rates

Variable rate	$3.50 per barrel produced for production up to 25 000 barrels per day (bpd). $2.95 per barrel produced above 25 000 bpd. $0.75 per barrel produced from East Foinaven
Fixed rate	$71 258 per day

Termination clauses

From Operator	24 months notice
From PGS Production	24 months if expected variable revenue fall below $102 250 per day. 12 months if expected variable revenue fall below $35 000 per day
Expected end of contract	2011

PETROJARL VARG

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.

If the revenues on the Varg field exceed $240 million in 2005 and 2006, we will share the upside 50/50 with Talisman. In 2005 we recorded a positive effect of $8.1 million after tax in relation to this profit sharing agreement.

MAIN TERMS AS OF DECEMBER 31, 2005

Rates

Variable rate	$6.30 per barrel
Fixed rate	$90 000 per day

Termination clauses

From Operator	90 days
From PGS Production	90 days if mean weekly production during normal operation falls below approximately 15 700 barrels per day
Expected end of contract	2008

RAMFORM BANFF

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.

MAIN TERMS AS OF DECEMBER 31, 2005

Rates

Variable rate	$5.00 per barrel produced for production up to 15 400 barrels per day (bpd). $3.00 per barrel for production above 15 400 bpd.
Fixed rate	GBP 40 000 per day (approximately $69 000)
Minimum rate	$126 800 per day

Termination clauses

From Operator	6 months
From PGS Production	None
Expected end of contract	2014

LEADERSHIP IN HSE

Our goal is zero injury to people and no danger to the environment. We work daily to achieve this.


BRISTOW

HEALTH, SAFETY, ENVIRONMENT & QUALITY IN PGS

PGS has maintained its leading position within health, safety, environment and quality in 2005 and has received recognition for system excellence and continuous improvement efforts throughout the year.

Formal improvement processes were developed and implemented in 2005. This included Management Systems, planning structure and assessment methods. We realize that improvement is a continuous process. Improvement principles are therefore applied on a continuous basis in our operations. Our Core Values and Corporate Social Responsibility principles are guiding us in this process.

By maintaining a competent and motivated work force and a robust working culture we strongly believe that we are well equipped to meet and manage future opportunities.

Our objective is to stay within the top tier within health, safety, environment and quality.

Specific areas of improvement in 2005:

- commitment to HSE&Q;
- identification, documentation and management of risk;
- structure and planning of our activities;
- self-monitoring and assessment; and
- analysis, investigation and learning.

The HSE&Q requirements and expectations are formalized in a Management Manual and a Management System Guideline, which reflect industry expectations and international standards such as ISO, OGP, IAGC and OHSAS. The system is developed and annually updated by each business unit as a joint effort.

MANAGEMENT COMMITMENT TO HSE&Q

The focus and documentation of Top Management Commitment to HSE&Q has been further strengthened. In 2005 we developed annual and individual HSE&Q plans for each of our Business Unit Presidents. The plans which are based on an annual self assessment define ambitious targets which are monitored on a monthly basis.

CORE VALUES, LEADERSHIP IN HSE AND PEOPLE FOCUS

We take pride in maintaining a safe working environment, which does not expose staff, families or the environment to uncontrolled risks. We still believe that the combination of robust systems and competence are key factors to success. Leadership in HSE means that we all take responsibility for our selves, our colleagues and the environment in which we operate.

FROM LAGGING TO LEADING FOCUS

We have throughout 2005 further developed our focus on leading indicators. We will continue to do so in 2006. By identifying trends or developments we expect to improve in the way we manage or remove risks. Through ISO 9001 certification of three of our Data Processing Centers in 2005 we believe we have further strengthened this focus.

CORPORATE RISK MANAGEMENT FRAMEWORK

We developed in 2005 a new Corporate Risk Management Framework based on principles lied down by COSO and international Risk Management Standards. The framework is being used cross divisionally within all disciplines, and helps us to manage and control our risks to the benefit of all stakeholders.

INCIDENT MANAGEMENT

A new and well acknowledged system for Incident Management has been implemented in 2005. Development of competence, focus on human, technological and organizational barriers as underlying causes, is key in our efforts to understand why things go wrong and how we may improve.

INTERFACE BETWEEN COMPETENCE AND TECHNOLOGY

We are in the forefront in using technology to grow competence and skills. In 2005 we developed further by implementing new interactive technology in the effort of improving competence. We expect this trend to accelerate further in the years to come.

CORPORATE SOCIAL RESPONSIBILITY (CSR)

We have well developed systems and traditions for integration of Corporate Responsibility Principles and Programs in our operations. Our Onshore Business Unit which operates in all continents has well developed systems which was recognized and awarded by customers and local communities in 2005.

Our objective is to succeed in integrating our resources in the communities we operate in, and thereby support and sustain development of local resources. The programs comprise activities such as education, training, medical health care and dental programs. Successful integration of resources is a key to succeed.

We were ranked as Best in Industry by Storebrand Funds in August 2005

PGS MARINE GEOPHYSICAL

PGS Marine Geophysical HSE&Q Performance in 2005 strengthened with one of the best TRCF (Total Recordable Frequency) figures to date and also a marked reduction of eye and back injuries as a result of initiatives started in 2004. In addition to these lagging indicators, our vessel operations increased the scope of data capture in the HSE&Q database by a factor of 20 since 2004, with the routine inclusion of non-conformances and unsafe act/condition report data. The database can now be used for a greatly wider scope of trend analysis in addition to a transparent action tracking system for all employees within Marine Geophysical.

Improvements in the Quality Management System gained ISO 9001: 2000 certification of three more Data Processing Centers in Cairo, Houston and Oslo. These centers are now utilizing the 3rd Generation Quality Management system incorporating common web based information and reporting tools worldwide.

Our commitment towards Occupational Health saw the development and release of the Occupational Health Manual for vessel operations. 2006 will see the principles of the management manual integrated into the operational, training and reporting routines of the seismic fleet.

The value of auditing and the use of quality philosophy for all aspects of health, safety and environment management have lead to a keen focus on structured and formalized audit plans for all offshore operations as well as the established office based internal and supplier based audits. Utilizing web-based tools incorporated in the HSE&Q management system audit results and findings are easily shared and tracked. The vessels and Management teams have been set key auditing targets to ensure that the system is operating optimally.

PGS ONSHORE

The Onshore business is facing the greatest geographical and cultural diversity within the Group. A modern and flexible management system, competent and motivated staff combined with a well developed and integrated social responsibility program, effectively support a strong and continuous improvement process.

Through client and industry networking PGS Onshore has strengthened its systematic approach and ownership to HSE&Q further in 2005. Simplicity and a strong commitment by the line produce high regularity and results. The organization strengths rest with the capacity to quickly adapt to new tasks and cultures.

PGS Onshore is leading in the Groups efforts to develop social responsibility programs and principles for implementation of our core values. Extensive experience with leading indicators and commitment has over a longer period supported the production of strong HSE&Q results.

PGS PRODUCTION

- *Petrojarl Foinaven* – 5 years without LTI
- *Petrojarl I* – 4 years without LTI
- *Ramform Banff* – 2 years without LTI
- *Petrojarl Varg* – 2 years without LTI

Throughout 2005, PGS Production has worked systematically to further improve its records. The support organization in Trondheim has a well developed Management System. This in combination with effective support systems and competent specialists effectively support and develop the offshore organizations. The organization has well developed systems and processes for Health, Safety, Environment, Quality and Security.

With the implementation of the Crisis Manager System, PGS Production has placed themselves in the forefront within Emergency Preparedness.

PGS Production operates in a well regulated regime and benefit greatly from the close cooperation with the operators as their customers. Well developed and instituted audit plans document and verify the company's capabilities and guide the management team towards business excellence.

HSE&Q OBJECTIVES 2006

The following overall HSE&Q objectives have been defined for 2006:

- To further develop competence at management and operational levels
- To align and simplify our Management Systems
- To improve in the way we identify, manage and mitigate risk
- Quality/improved audit programs and non-conformance management
- Behavioral programs

THE PGS SHARE

PGS is committed to serve the financial community with good, relevant and timely information regarding the company. PGS policy is to treat all stakeholders equal.

SHAREHOLDER POLICY

All information from us that is considered relevant for our shareholders is published via the Oslo Stock Exchange (OSE), sent to the New York Stock Exchange (NYSE) and posted on our web site, www.pgs.com. We hold public presentations and arrange conference calls in relation to our quarterly results. We host an annual Capital Markets Day and our management visits regularly investors in the United Kingdom and US as well as attending external conferences.

We have been awarded both the Information Symbol and the English Symbol by the Oslo Stock Exchange. The information symbol is awarded to companies that meet, among other things, defined standards for information on their web site. The English Symbol is awarded to companies that meet all the requirements for the Information Symbol in English.

DIVIDEND POLICY AND SHARE BUY BACKS

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

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

As of December 31, 2005, our Board of Directors had no authorization to buy back PGS shares. We did not own any shares in PGS as of December 31, 2005.

AUTHORIZATION TO INCREASE THE SHARE CAPITAL

At the Annual General Meeting on June 8, 2005 our Board of Directors was authorized to increase our share capital by up to NOK 60 million at par value NOK 10 per share through new subscription for shares in return for cash and/or non-cash contributions. The authorization is valid for a period of two years from its effective date, and had not been used as of December 31, 2005.

CAPEX GUIDANCE

We have guided for a capital expenditure in Marine Geophysical and Onshore of $100 to $110 million in 2006, in addition to the investments on the new Ramform seismic vessel. The capital expenditure in PGS Production will depend upon specific projects. In addition we plan to double our multi-client investments in 2006 from the levels in 2005 of $55.7 million. The total payments relating to the new Ramform seismic vessel in 2006 are estimated to be approximately $55 million.

SHARE FACTS

PGS' ordinary shares are primary listed on the OSE under the symbol "PGS", nominated in Norwegian kroner ("NOK"). PGS' shares are also traded on NYSE in the form of American Depositary Shares (ADS) under the symbol PGS, nominated in U.S. dollars ($). Each ADSs represents one share. In 2005 a total of 154.4 million PGS shares were traded on OSE, with an average volume of 593 994 shares per day. On NYSE 23.2 million ADSs in PGS were traded, with an average volume of 89 391 ADSs per day. PGS has 60 million shares outstanding.

SHARE PERFORMANCE

The PGS share closed at NOK 208 on the last trading day of 2005 on OSE, an increase of 65% over the year. During the year the highest closing price was NOK 211 on October 3, while the lowest closing price was NOK 120.67 on May 18. During 2005 the Oslo Stock Exchange Benchmark Index (OSEBX) rose by 40%, while the Oslo Stock Exchange Energy Index (OSE10GI) rose by 80%.

On NYSE, PGS closed at $30.99 on December 30, 2005, an increase of 50% over the year. During the year the highest closing price was $31.82 on September 30, while the lowest closing price was $18.91 on May 17. During 2005 the Standard & Poor's 500 Index increased by 3%, while the Philadelphia Oil Service Index (OSX) increased by 47%.

The market value of PGS as of December 31, 2005 was NOK 12 480 million ($1 859 million).

ANALYST COVERAGE

As of December 31, 2005 there were twelve equity sell side analysts that covered PGS on a regular basis with market updates and estimates for PGS's financial results. Out of these, one is based in London, two are based in New York, while one is based in Paris. The other analysts are Oslo based.

SHAREHOLDERS

At the end of 2005, PGS had 2 879 registered shareholders according to the Norwegian Central Securities Depository (VPS).

Non-Norwegian investors owned approximately 80% of the share, with United Kingdom and United States as dominant. The Norwegian ownership stood at approximately 20%. As of December 31, 2005 three investors had flagged an ownership above 5% in PGS; Fidelity Investments, Blue Ridge and Umoe Industri.

2006 ANNUAL GENERAL MEETING

The annual shareholders meeting for PGS in 2006 is scheduled to take place June 14, 2006, at the Company's headquarters at Lysaker, Strandveien 4, Oslo, Norway.

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 register maintained at the VPS within two working days before the general meeting.

Shareholders who wish to attend the meeting are asked to inform our registrar:

PGS' 20 LARGEST SHAREHOLDERS AS OF 31 DECEMBER 2005

Rank	Shareholder	Shares	Percentage	Country	Account
1	CITIBANK, N.A.	8 013 790	13.4	USA	Nominee
2	MORGAN STANLEY & CO.	4 153 664	6.9	GBR	Nominee
3	STATE STREET BANK &	3 258 683	5.4	USA	Nominee
4	UMOE INDUSTRI AS	3 037 332	5.1	NOR	Ordinary
5	FIDELITY FUNDS-EUROP	2 896 158	4.8	LUX	Ordinary
6	MORGAN STANLEY & CO.	2 568 142	4.3	GBR	Nominee
7	BEAR STEARNS SECURIT	1 601 845	2.7	USA	Nominee
8	JPMORGAN CHASE BANK	1 286 720	2.1	GBR	Nominee
9	BANK OF NEW YORK, BR	1 172 492	2.0	GBR	Ordinary
10	CITIBANK NA	1 128 707	1.9	USA	Nominee
11	MORGAN STANLEY AND C	1 122 349	1.9	GBR	Nominee
12	VITAL FORSIKRING ASA	950 090	1.6	NOR	Ordinary
13	JPMORGAN CHASE BANK	822 090	1.4	GBR	Ordinary
14	STATE STREET BANK &	751 088	1.3	USA	Nominee
15	GOLDMAN SACHS & CO	717 214	1.2	GBR	Nominee
16	ODIN NORDEN	550 700	0.9	NOR	Ordinary
17	DNB NOR NORGE (IV) V	539 089	0.9	NOR	Ordinary
18	SKANDINAVISKA ENSKIL	537 350	0.9	SWE	Nominee
19	FORTIS BANK LUXEMBOU	524 216	0.9	LUX	Ordinary
20	BANK OF NEW YORK, BR	519 402	0.9	LUX	Ordinary

1) Citibank is PGS ADR registrar

PGS SHAREHOLDERS' CITIZENSHIP AS OF 31 DECEMBER 2005

Country	Holders	Shares	% of Total
United Kingdom	119	20 086 339	33.5%
USA	112	17 568 376	29.3%
Norway	2 405	12 221 538	20.4%
Other Countries	243	10 123 747	16.9%
Total	2 879	60 000 000	100.0%

Nordea Bank Norge ASA
Issuer Services
P.O. Box 1166 Sentrum
0107 Oslo
Fax: +47 22 48 63 49
Tel: +47 22 48 62 62

Owners of ADSs can vote by surrendering their ADSs to our ADS registrar, Citibank, and having title to the related shares registered in our share register maintained at the VPS prior to the meeting.

CONTACT INFORMATION FOR ADR HOLDERS

Our depositary bank for PGS ADRs is Citibank. They could be reached at:

Citibank Shareholder Services
P.O.Box 43077
Providence, RI 02940-3077
United States
Toll free: +1 877 CITI ADR
Outside the US Tel: +1 816 843 4281
Fax: +1 201 324 3284
e-mail: citibank@shareholders-online.com

RISK ADJUSTMENT

(Norwegian resident shareholders only)

The RISK-amount for PGS at January 1, 2005, is estimated to be NOK 0.00 per share. RISK is the Norwegian abbreviation for the company's retained earnings after tax, calculated on an annual basis.

Beginning with the 2006 income year, the RISK method is abolished, and the Shareholder model is introduced. According to this model, individual shareholder's income from shares (dividends and capital gains) is taxable as ordinary income (28 per cent flat rate) to the extent the income exceeds a basic tax-free allowance. Any unused allowance may be set off against gains on the realisation of shares.

RATING

As of December 31, 2005 PGS had a "Ba3" rating from Moody's Investors Service and a "B+" rating from Standard & Poor's. Moody's has a developing outlook, while S&P has a positive outlook.

INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

Effective January 1, 2005 publicly traded companies in European Union (EU) and European Economic Area (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 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.

PGS versus market 2005

PGS share price (NOK) versus market and sector

PGS versus US market 2005

PGS share price $ versus market and sector

CORPORATE GOVERNANCE IN PGS

PGS is committed to maintain high standards of corporate governance. PGS believes that effective corporate governance is essential to the well being of the company and establishes the framework by which PGS conducts itselves in delivering services to its customers and value to PGS' shareholders.

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

Our corporate governance principles are adopted by our Board of Directors. Below is a summary of our principles. Our articles of association, in addition to full versions of our corporate governance principles, our rules of procedures for our Board of Directors (Board), our Audit Committee charter, our Remuneration Committee charter and our Nomination Committee charter are available on our website (www.pgs.com).

CODE OF CONDUCT AND CORE VALUES

We have 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 and Core Values are presented below and are also available in full versions on (www.pgs.com).

BUSINESS

Our business is defined in our 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 our business areas are presented on page 6 and page 7 of this annual report.

EQUITY AND DIVIDENDS

Our dividend polcy is described on page 32 in this annual report.

Our Board is continually considering opportunities to expand and further develop our business activities, including but not limited to mergers and acquisitions, and to strengthen our capital base. Our Board was authorized at the annual general meeting in June 2005 to increase our share capital by up to NOK 60 million through new subscription for shares. Our shareholders pre-emption rights to subscribe for new shares can be waived. Our Board of Directors believe this is necessary to provide required flexibility, and therefore, is in our best interest. The authorization is valid for a period of two years from its effective date, and had not been used as of December 31, 2005.

As of December 31, 2005, we did not have an authorization to buy back our own shares.

EQUAL TREATMENT OF SHAREHOLDERS AND TRANSACTIONS WITH RELATED PARTIES

We have one class of shares. In our general meetings each share has one vote. Our Board 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 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 us 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 us and related parties shall be conducted at market values. Material transactions will be subject to independent valuation by third parties. According to our Code of Conduct, none of our employees shall have any personal or financial interest, which might conflict with ours or influence or appear to influence their judgment or actions in carrying out their responsibilities to PGS. According to our Rules of Procedures, a member of our Board may not participate in the discussion or decision of issues, where the director, or to any person closely related to the director, have material personal or financial interest in the matter.

FREELY TRANSFERABLE SHARES

Our shares are freely transferable except that an acquisition by assignment shall be contingent upon approval by our Board, which cannot be withheld without reasonable grounds.

GENERAL MEETINGS

Through the General Meetings our shareholders exercise ultimate authority and elect the members of our Board and the chairperson.

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 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.

In accordance with our Articles of Association, the Chairperson of the Board of Directors chairs the General Meeting.

NOMINATION COMMITTEE

In 2005, our Annual General Meeting voted to establish a Nomination Committee and to amend the Articles of Association to include a section regarding a nomination committee. According to the amended Articles of Association, we shall have a Nomination Committee consisting of three members to be elected by our shareholders at the general meeting. The majority of the members of the Committee shall qualify as "independent". The term of service shall be two years unless the General Meeting determines that the period shall be shorter. The Nomination Committee's main duties are to propose nominees for election as members and chairperson to the Board of Directors and the Nomination Committee, and to propose the fees to be paid to the members of the Board and the Nomination Committee. The Nomination Committee shall provide a report to our shareholders prior to the general meeting.

THE CURRENT NOMINATION COMMITTEE

The current members of the Nomination Committee consist of Roger O'Neil (chairperson), Hanne Harlem and C. Maury Devine. Shareholders who wish to propose new board members to PGS could do so by sending an e-mail to Mr. O'Neil at ir@pgs.com. None of the members of our Nomination Committee are employed by us or are members of our Board. In 2005, our Nomination Committee had two meetings. A report regarding the work of our Nomination Committee will be distributed with the calling notice to our Annual General meeting.

BOARD OF DIRECTORS – COMPOSITION AND INDEPENDENCE

According to our articles of association our Board shall have from three to eight directors. The Board 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 and all of the members of the Audit and Remuneration Committees as "independent directors"; and
- annual review and determination of the independence of each director.

No member of our Board shall be an executive of PGS. Directors cannot perform paid consultancy work for us. 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 our Board affirmatively determines that the director has no material relationship with us.

At its meeting held on March 22, 2006, our Board affirmatively determined that each of Francis Gugen, Keith Henry, Harald Norvik, Rolf Erik Rolfsen, Clare Spottiswoode and Anthony Tripodo has no material relationship with us and that each is therefore an "independent" director under applicable NYSE listing standards.

Shareholders and other interested parties may communicate directly with our independent directors by sending a written letter in an envelope addressed to Petroleum Geo-Services "Board of Directors (Independent Members)", General Counsel Erlend Bakken, P.O. Box 89, 1325 Lysaker, Norway.

THE CURRENT BOARD OF DIRECTORS

As of December 31, 2005, the Board consisted of seven shareholder representatives. Neither the CEO nor any other member of the executive management in PGS is a director of the Board. The current members of the Board are presented on page 40 and 41 of this annual report and on (www.pgs.com).

THE WORK OF THE BOARD OF DIRECTORS

In accordance with Norwegian corporate law, our Board has overall responsibility for management of our Company, while our CEO is responsible for day-to-day management. Our Board supervises our CEO's day-to-day management and our activities in general. It is also responsible for ensuring that appropriate steering and control systems are in place. Our 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. In 2005 our Board had 13 meetings.

Our Board 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 our Board's responsibility to decide our financial targets and determine our overriding strategy in collaboration with our CEO and our executive committees, and to approve our business plans, budgets and frameworks. In its supervision of our business activities, our Board will seek to ensure that there exist satisfactory routines for follow-up of principles and guidelines required by our 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 our Board to determine whether our Board and its committees are functioning effectively. The tasks and duties of our CEO vis-à-vis our Board are outlined in the rules along with the tasks and duties of the chairperson of our Board. Our Board shall have a vice-chairperson to chair our Board in our chairperson's absence. The full version of the rules of procedures for our Board of Directors is available on (www.pgs.com).

Our governance structure is organized as described below:

Our Board is responsible for the development and supervision of our business activities. Our Board has established Audit and Remuneration Committees to assist in organizing and carrying out its responsibilities.

- Our Board of Directors appoints our CEO.
- Our CEO is responsible for the day-to-day management of our activities.
- Our CEO has organized our Executive committees and our Disclosure Committee to further assist in discharging our CEO's responsibilities.
- Our Board, along with our CEO, is committed to operating PGS in an effective and ethical manner in order to create value for our shareholders. Our Code of Conduct requires our management to maintain an awareness of the risks to PGS in carrying out our business strategies and not to put personal interests ahead of or in conflict with the interests of PGS.
- Our CEO, under the oversight and guidance of our Board and our Audit Committee, is responsible for ensuring that our financial statements fairly present in all material respects our financial condition and results of operations and that we make timely disclosures needed to assess our financial and business soundness and risks.

BOARD COMMITTEES

Our Audit Committee consists of the board members Francis Gugen (chairperson), Harald Norvik and Anthony Tripodo. Its function is to; assist our 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. Our Audit Committee is composed of members that satisfy the SEC's and the NYSE's independence requirements.

Our Remuneration Committee consists of the board members Keith Henry (chairperson) and Rolf Erik Rolfsen. The function of the Committee is to assist with the matters relating to the compensation, benefits and perquisites of our CEO and other senior executives.

In 2005 our Audit Committee had 9 meetings while our Remuneration Committee had 7 meetings.

REMUNERATION OF THE BOARD OF DIRECTORS AND THE EXECUTIVE MANAGEMENT

The remuneration of the members of the Board is not linked to our 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 us in addition to their appointment as a Member of the Board.

For the year ended December 31, 2005, the aggregate amount we paid for compensation to our directors for services in all capacities during 2005 was $548 705.

The remuneration to our Board will be proposed by the Nomination Committee according to its charter at our Annual General Meeting.

Svein Rennemo, president and Chief Executive Officer, received $607 454 in fixed salary and other compensation in 2005. In addition, Rennemo received $177 440 in 2004 bonus paid during 2005 including share purchase bonus. Under our 2005 bonus incentive plan, our Board has determined that Rennemo is entitled to a cash bonus of $240 246 and a share purchase bonus of $144 147.

The net share purchase bonus amount, after withholding taxes, must be used to buy PGS shares at prevailing market prices and held for a minimum of three years.

INFORMATION AND COMMUNICATIONS

Our Board is committed to report financial results and other relevant information based on openness and taking into account the requirement for equal treatment of all participants in the securities market. As a listed company, we comply with relevant regulations regarding disclosure. Announcements 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). Our shareholder policy is described on page 32 in this annual report.

TAKE-OVERS

Our Board will not seek to hinder or obstruct any take-over bids for our activities or shares, or exercise mandates or pass any resolutions that obstruct take over bids that are put forward.

AUDITOR

Our Audit Committee shall support the Board in the administration and exercise of its responsibility for supervisory oversight of the work of the independent auditors, which shall keep our Board informed of all aspects of its work for PGS. This includes submission of an annual plan for the audit of PGS. The auditor meets our Audit Committee at least once a year without management present. Our internal procedures limit the use of services from our auditors.

The independent auditor shall meet our Audit Committee at least once a year in connection with the preparation of the annual accounts, and at least once a year present to our Audit Committee a review of our 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 our Audit Committee with a summary of all services in addition to audit work that have been undertaken for us. The remuneration paid to the auditor will be reported to the Annual General Meeting for approval.

CORE VALUES

Leadership in HSE

We strive to establish and maintain a 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

We have 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 we conduct 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).

PGS BOARD OF DIRECTORS

JENS ULLTVEIT-MOE (63)
Chairperson (elected 2002)

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

KEITH HENRY (61)
Vice chairperson (elected 2003)

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

CLARE SPOTTISWOODE (53)
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 board of Economatters Ltd. and is a non-executive director of BioFuels, Bergesen Worldwide Gas ASA and Tullow Oil plc.. She is also a member of the board of the Department of Health Commercial Advisory Board and a Policy Holder Advocate for Aviva. She previously held several non-executive director positions including Booker plc.. She was director general of Ofgas, the UK Gas Regulation Organization, from 1993 to 1998. In 1993 she served as a member of the UK Deregulation Task Force, and from 1998 to 2002 sat on the UK Public Services Productivity Panel. Her career started as an economist with the HM Treasury before establishing her own software company. In 1999 she was made a Commander of the Order of the British Empire for services to industry, and holds degrees in economics from Cambridge and Yale University.

FRANCIS GUGEN (57)
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, chairperson of the Board of Directors for Oslo Stock Exchange, member of the Board of Directors in ConocoPhillips and chairperson of the Supervisory Board in DnB NOR ASA. He served as chief executive officer of Statoil ASA from 1988 to 1999. He was finance director and a member of the executive board of the Aker Group from 1981 to 1988. He served as personal secretary to the Prime Minister of Norway and as Deputy Minister in The Ministry of Petroleum and Energy from 1979 to 1981. Mr. Norvik has a Master of Science Degree in Business from The Norwegian School of Economics and Business Administration.

ROLF ERIK ROLFSEN (65)

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 (53)

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 Helix Energy Solutions Group, Inc. (formerly Cal Dive International) and Vetco International Limited, both oilfield service companies, based in Houston, Texas and London, England, respectively. From 1997 to April 2003, Mr. Tripodo served at Veritas DGC in various capacities, including executive vice president and chief financial officer. He also has held various senior executive and financial roles at Baker Hughes and PricewaterhouseCoopers. Mr. Tripodo has a B.A. degree from St. Thomas University.

PGS EXECUTIVE OFFICERS

SVEIN RENNEMO (58)
President and CEO

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

GOTTFRED LANGSETH (39)
Senior Vice President and CFO

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

RUNE ENG (44)
President Marine Geophysical

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

ERIC WERSICH (42)
President 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.

ESPEN KLITZING (42)
President Production

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

OTHER SENIOR 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

BJØRN KORSVEIEN
Vice President Finance

GEIR OLSEN
Corporate Business Controller

CHRISTIN STEEN-NILSEN
Vice President Chief Accounting Officer

US GAAP FINANCIAL REVIEW

RESULTS OF OPERATIONS

OVERVIEW

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

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

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

REVENUES

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

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

Our revenues for 2005 increased by $66.8 million as compared with 2004. Marine Geophysical increased by $153.9 million, while Onshore revenues increased by $19.3 million. These increases were offset by a reduction of revenues from Pertra, which was sold in March 2005, of $147.4 million, offset by a decrease in elimination of inter-segment revenues of $58.5 million, mainly caused by 70% of the revenues from *Petrojarl Varg* being reported as external from March 2005 as a result of the sale of Pertra. Total Production revenues decreased $17.5 million.

Marine Geophysical

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

Onshore

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

Production

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

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

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

COST OF SALES

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

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

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

Cost of sales (services)

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

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

Cost of sales (products)

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

Eliminations

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

EXPLORATION COSTS

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

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

DEPRECIATION, DEPLETION AND AMORTIZATION

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

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

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

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

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

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

SELLING, GENERAL AND ADMINISTRATIVE COSTS

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

IMPAIRMENT OF LONG-LIVED ASSETS

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

GAIN ON SALE OF SUBSIDIARIES, NET

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

OTHER OPERATING (INCOME) EXPENSE, NET

We recorded other operating income, net, of $26.1 million in 2005. The amount includes a gain of $17.2 million from the release of liabilities related to our UK leases and a gain of $8.9 million from the successful resolution of a claim against an equipment supplier. In 2004 we recorded other operating expense, net, of $8.1 million, primarily relating to costs to complete the 2002 U.S. GAAP consolidated financial statements and the re-audit of our U.S. GAAP financial statements for the year ended December 31, 2001.

INTEREST EXPENSE AND OTHER FINANCIAL ITEMS

Interest expense for 2005 amounted to $96.4 million, a reduction of $14.4 million from 2004. The decrease reflects a significant reduction of interest-bearing debt and capital leases between the two periods.

Income from associated companies totaled $0.3 million in 2005 compared to $0.7 million in 2004.

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

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

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.

INCOME TAX EXPENSE

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

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

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

DISCONTINUED OPERATIONS

In 2005, we recognized income from discontinued operations, net of tax, of $0.5 million relating to the sale of our Production Services subsidiary in 2002. In 2004, we recognized income from discontinued operations, net of tax, of $3.0 million relating to the same subsidiary.

OPERATING PROFIT (LOSS) AND NET INCOME (LOSS)

Operating profit for 2005 was $335.4 million, compared to a profit of $35.7 million for 2004.

We reported net income of $112.6 million for 2005, compared to a net loss of $134.7 million for 2004.

SEGMENT OPERATING PROFIT

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

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

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

Marine Geophysical

Marine Geophysical reported a segment operating profit of $150.2 million in 2005 compared to a loss of $35.0 million in 2004. This improvement was primarily driven by a significant improvement in contract performance and lower multi-client amortization rates.

Onshore

Onshore recorded a segment operating loss of $9.8 million in 2005 compared to a loss of $4.5 million in 2004. The weak result, despite increased revenues, relates primarily to mobilization and start-up costs for projects at the end of 2005. Onshore is expected to realize strong results in the first half of 2006 because a significant portion of mobilization costs on large projects have been recognized in 2005, while most of the revenue generating activities will be performed in 2006.

Production

Production recorded a segment operating profit of $43.5 million in 2005, which represents a reduction of $34.3 million from 2004. This reduction was caused by a combination of a reduction of revenues from all vessels except *Petrojarl Varg* and increased costs.

Pertra

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

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

OUTLOOK

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

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

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

MARINE GEOPHYSICAL

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

ONSHORE

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

PRODUCTION

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

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

LIQUIDITY AND CAPITAL RESOURCES

LIQUIDITY — GENERAL

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

SOURCES OF LIQUIDITY — CAPITAL RESOURCES

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

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

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

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

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

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

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

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

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

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

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

- our total leverage ratio may not exceed 3.50 to 1.0 in 2006, 3.25 to 1.0 in 2007 and 3.00 to 1.0 in 2008 and may not exceed 3.00 to 1.0 at the time of our proposed separation transaction
- our consolidated interest coverage ratio (defined as the ratio of consolidated EBITDA, as defined in the credit agreement, reduced by multi-client investments to consolidated interest expense) must be at least 3.0 to 1.0, and
- our consolidated fixed charge coverage ratio (defined as the ratio of consolidated EBITDA, as defined in the credit agreement, reduced by multi-client investments to consolidated fixed charges) must be at least 1.3 to 1.0.

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

We experience some seasonality in our business, and our capital requirements may be impacted by this seasonality.

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

NET CASH USED IN OR PROVIDED BY INVESTING AND FINANCING ACTIVITIES

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

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

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

In 2005 we repaid all of our $250 million 8% Senior Notes at a redemption premium totaling $4.3 million. We also repaid $741.3 million of the $745.9 million 10% Senior Notes at a tender and consent premium of $101.2 million. Costs associated with refinancing the long-term debt were approximately $9.9 million, capitalized as deferred debt issue costs.

CAPITAL REQUIREMENTS AND COMMITMENTS

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

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

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

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

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

Business Segments

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

For 2006, we expect:

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

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

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

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

LONG-TERM CONTRACTUAL OBLIGATIONS

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

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

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

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

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

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

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

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

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

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

UK LEASES

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

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

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

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

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

Additional required rental payments were $7.2 million for each of the years ended December 31, 2005 and 2004.

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

RESEARCH AND DEVELOPMENT

We incurred research and development costs of $9.9 million and $3.4 million during the years ended December 31, 2005 and 2004, respectively. For additional information regarding our research and development policies and expenditures, please see our consolidated statements of operations in the notes to this annual report.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

INTEREST RATE RISK

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

Debt:

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

**1, 3 or 6 month LIBOR rate*

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

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

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

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

FOREIGN CURRENCY EXCHANGE RATE RISK

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

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

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

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

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

COMMODITY RISK

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

Petroleum Geo-Services ASA and Subsidiaries:

CONSOLIDATED BALANCE SHEETS

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

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

Petroleum Geo-Services ASA and Subsidiaries:

CONSOLIDATED STATEMENTS OF OPERATIONS

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

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

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

Petroleum Geo-Services ASA and Subsidiaries:

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

Petroleum Geo-Services ASA and Subsidiaries:

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

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

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

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

Petroleum Geo-Services ASA and Subsidiaries:
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 GENERAL INFORMATION ABOUT THE COMPANY AND BASIS OF PRESENTATION

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

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

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

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

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

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

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

CONSOLIDATION AND EQUITY INVESTMENTS

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

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

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

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

VARIABLE INTEREST ENTITIES

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

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

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

DISCONTINUED OPERATIONS

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

USE OF ESTIMATES

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

CASH AND CASH EQUIVALENTS

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

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

FOREIGN CURRENCY TRANSLATION

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

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

OPERATING AND CAPITAL LEASES

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

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

UK LEASES

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

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

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

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

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

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

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

RECEIVABLES CREDIT RISK

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

PROPERTY AND EQUIPMENT

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

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

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

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

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

MULTI-CLIENT LIBRARY

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

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

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

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

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

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

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

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

OTHER INTANGIBLE ASSETS

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

OTHER LONG-LIVED ASSETS

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

IMPAIRMENT OF MULTI-CLIENT LIBRARY

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

The estimation of future cash flows and fair value is highly subjective and inherently imprecise. Estimates can change materially from period to period based on many factors including historical and recent revenue trends, oil and gas prospects in particular regions, general economic conditions affecting the Company's customer base, expected changes in technology and other factors that are deemed relevant.

IMPAIRMENT OF LONG-LIVED ASSETS (EXCLUDING MULTI-CLIENT LIBRARY)

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

STEAMING AND MOBILIZATION

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

DERIVATIVE FINANCIAL INSTRUMENTS

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

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

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

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

REVENUE RECOGNITION

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

REVENUE SERVICES

1. Geophysical Services (Marine, Onshore and Other)

(a) Sales of Multi-Client Library Data

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

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

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

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

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

(b) Proprietary Sales/ Contract Sales

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

(c) Other Geophysical Services

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

2. Production Services

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

3. Revenue Products (Pertra)

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

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

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

INCOME TAXES

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

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

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

ASSET RETIREMENT OBLIGATIONS

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

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

COMMITMENTS AND CONTINGENCIES

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

FRESH-START REPORTING

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

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

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

OIL AND NATURAL GAS ASSETS

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

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

2004, respectively, while there were no such costs for the year ended December 31, 2003.

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

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

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

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

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

NEW ACCOUNTING STANDARDS

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

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

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

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

NOTE 3 2003 FINANCIAL RESTRUCTURING AND FRESH-START REPORTING

BACKGROUND OF RESTRUCTURING

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

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

FINANCIAL RESTRUCTURING

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

- $746 million of unsecured 10% Senior Notes, due 2010;
- $250 million of unsecured 8% Senior Notes, due 2006;
- $4.8 million of an eight-year unsecured senior term loan facility (which the Company fully repaid in May 2004);
- 91% of new ordinary shares of PGS as constituted immediately post restructuring, with an immediate reduction of this shareholding to 61% through a rights offering of 30% of the new ordinary shares to the

pre-restructuring shareholders for $85 million, or $14.17 per share; and

- $40.6 million of cash, of which $17.9 million was distributed in December 2003 and $22.7 million in May 2004.

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

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

REORGANIZATION VALUE

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

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

FRESH-START REPORTING

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

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

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

PGS ASA Plan of Reorganization Recovery Analysis

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

Adjusted for fair value adjustment of interest rate variation on UK leases	$ 51 642
Adjusted for cash	(148 912)
Reorganization value	$ 1 516 400

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

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

- The reorganization value of the Company was allocated to the Company's assets in conformity with the procedures specified by Statement of Financial Accounting Standards No. 141, "Business Combinations." The sum of the amounts assigned to assets and liabilities was within the range of the estimated reorganization value and close to the mid-range of the valuation. Therefore, there was no excess or deficit value to be allocated to goodwill or long-term assets.
- Each liability and contingency existing as of the fresh-start reporting date, other than deferred taxes, has been stated at the present value of the amounts to be paid, determined at appropriate then current interest rates.
- Deferred taxes were recorded in conformity with applicable income tax accounting standards, principally Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes". Deferred tax assets and liabilities have been recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities (see Note 21). Valuation allowances have been provided for deferred tax assets.
- Changes in existing accounting principles that otherwise would have been required in the consolidated financial statements of the emerging entity within the twelve months following the adoption of fresh-start reporting were adopted at the time fresh-start reporting was adopted.
- Resetting the multi-client library, the property and equipment and oil and natural gas assets to fair value and eliminating all of the accumulated depreciation.

NOTE 4 NET GAIN ON SALE OF SUBSIDIARIES

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

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

NOTE 5 IMPAIRMENT OF LONG-LIVED ASSETS AND OTHER OPERATING (INCOME) EXPENSE, NET

Impairments of long-lived assets consist of the following:

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

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

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

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

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

NOTE 6 SHARES AVAILABLE FOR SALE AND INVESTMENTS IN SECURITIES

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

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

NOTE 7 ACCOUNTS RECEIVABLE, NET

Accounts receivable, net, consists of the following:

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

The change in allowance for doubtful accounts is as follows:

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

NOTE 8 OTHER CURRENT ASSETS

Other current assets consist of the following:

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

NOTE 9 PROPERTY AND EQUIPMENT, NET

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

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

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

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

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

The following table summarizes depreciation expense:

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

SUBSEQUENT EVENTS

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

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

NOTE 10 MULTI-CLIENT LIBRARY, NET

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

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

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

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

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

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

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

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

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

NOTE 11 OTHER INTANGIBLE ASSETS, NET

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

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

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

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

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

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

NOTE 12 OTHER LONG-LIVED ASSETS

Other long-lived assets consist of the following:

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

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

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

As described in Note 10, the reduction of the valuation allowance for deferred tax assets established in fresh-start accounting results in a reduction of certain intangible assets. At December 31, 2005 and 2004, the Company recorded $0.5 million and $1.0 million, respectively, in reduction of the carrying amounts of favorable lease contracts due to reversal of valuation allowance (see Note 21).

NOTE 13 ACCRUED EXPENSES

Accrued expenses consist of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Accrued employee payroll	$ 44 864	$ 37 659
Accrued vessel operating expenses	30 074	17 080
Customer advances and deferred revenue	29 723	12 070
Forward exchange contracts (Note 19)	7 234	—
Received, not invoiced, property and equipment	7 967	5 618
Accrued commissions	7 550	9 683
Accrued interest expenses	5 778	3 394
Liabilities of business transferred under a contractual arrangement (Notes 4 and 24)	3 504	—
Accrued severance	27	290
Other	27 606	29 462
Total	$ 164 327	$ 115 256

Changes in accrued severance and restructuring costs are as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Beginning balance	$ 290	$ 5 061	$ 8 367	$ 1 215
Additional and adjustment of allowances	(40)	(632)	1 764	18 469
Severance and restructuring costs paid	(223)	(4 139)	(5 070)	(11 317)
Ending balance	27	$ 290	$ 5 061	$ 8 367

NOTE 14 OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Accrued liabilities UK leases (Note 20)	$ 50 765	$ 79 344
Pension liability (Note 22)	45 443	52 472
Asset retirement obligations ("ARO") (Note 2)	20 015	58 518
Tax contingencies	19 184	25 522
Interest rate swaps (Note 19)	1 628	—
Other	3 755	3 794
Total	$ 140 790	$ 219 650

The following table presents changes in asset retirement obligations for the years ending December 31, 2005 and 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Balance at beginning of period	$ 58 518	$ 50 016	$ 49 847	$ 59 767
Accretion expense	1 426	4 005	599	3 793
Liabilities settled in the period	(15)	—	(430)	—
Disposal of subsidiary (Pertra AS)	(39 914	—	—	—
Revision in estimated cash flow/fair value	—	4 497	—	(13 713)
Balance at end of period	$ 20 015	$ 58 518	$ 50 016	$ 49 847

The ARO liability as of December 31, 2005 relates mainly to the Banff field and will be settled at the end of the contract, currently expected to be no later than 2014.

As of December 31, 2005, the Company had asset retirement obligations for the sub-sea production facility associated with *Ramform Banff* FPSO operating in the North Sea. These obligations generally relate to restoration of the environment surrounding the facility and removal and disposal of all the production equipment. The asset retirement obligation will be covered in part by contractual payments from FPSO contract counterparties (see Note 12). The receivable has been included in the consolidated balance sheets under other long-lived assets.

NOTE 15 SHORT-TERM DEBT AND CURRENT PORTION OF LONG-TERM DEBT

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

	December 31,	
(In thousands of dollars)	2005	2004
Short-term debt (see Note 16)	$ 2 674	$ 1 962
Current portion of long-term debt (see Note 16)	21 732	17 828
Total	$ 24 406	$ 19 790

NOTE 16 DEBT

LONG-TERM DEBT

Long-term debt consists of the following:

(In thousands of dollars)	December 31, 2005	2004
Unsecured:		
10% Senior Notes, due 2010	$ 4 624	$ 745 949
8% Senior Notes, due 2006	—	250 000
Secured:		
Term loan, due 2012, Libor + margin (see below)	850 000	—
8.28% First Preferred Mortgage Notes, due 2011	87 930	98 920
Other loans, due 2006	1 312	8 149
Total debt	943 866	1 103 018
Less current portion	(21 732)	(17 828)
Total long-term debt	$ 922 134	$ 1 085 190

Aggregate maturities of long-term debt as of December 31, 2005 are as follows:

(In thousands of dollars)	December 31, 2005
Year of repayment:	
2006	$ 21 732
2007	21 400
2008	22 540
2009	23 660
2010	29 554
Thereafter	824 980
Total	$ 943 866

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

The Company has hedged the interest rate on 50% of the borrowings under the Term Loan by entering into interest rate swaps where the Company receives floating interest rate based on 3 months LIBOR and pays fixed interest rate payments based on LIBOR for 3 and 5 year maturities. See Note 19 for further information.

The 10% Senior Notes due 2010 ("10% Notes") bear interest at 10% per annum payable semi-annually and mature in November 2010 with no required principal payments until maturity. The 10% Notes are callable by the Company beginning in November 2007 and are callable thereafter at par plus a premium of 5% declining linearly until maturity. In December 2005, the Company refinanced and retired $741.3 million of the 10% Notes. The 10% Notes are unsecured obligations of PGS ASA.

The 8.28% First Preferred Mortgage Notes due 2011 ("8.28% Notes") bear interest at 8.28% per annum, and interest and scheduled principal amounts are payable semi-annually. The 8.28% Notes are subject to redemption at par on a pro rata basis through operation of a mandatory sinking fund on a semi-annual basis according to a schedule and are subject to optional redemption by the Company beginning in June 2006 at a redemption price equal to 100% of the principal amount plus a make whole premium that is based on U.S. treasury rates plus 0.375%. The 8.28% Notes are secured by, among other things, a mortgage on the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. In addition, there is established under the indenture for the 8.28% Notes a debt service reserve fund, which was initially funded in an amount (approximately $10 million) equal to the maximum interest and sinking fund payment due on the 8.28% Notes on any payment date for such notes through December 1, 2010. Such additional amount has been invested in a funding agreement that serves as a source of funds that, together with charter hire payments made by a Company subsidiary under charters for the *Ramform Explorer* and the *Ramform Challenger* vessels, are used to make debt service payments on the 8.28% Notes. This debt service reserve fund investment is presented as long-term restricted cash in the consolidated balance sheets because funds derived from the investment will be used to make final debt service payments on the 8.28% Notes.

BANK CREDIT FACILITIES

In December 2005, the Company replaced its secured $110 million revolving credit facility, originally maturing in 2006, with a new revolving credit facility ("RCF") of $150 million. The new RCF is part of the same credit agreement as the $850 million Term Loan described above and matures in 2010. The Company may use up to $60 million of capacity under the RCF for letters of credit and may borrow U.S. dollars, or any other currency freely available in the London banking market to which the lenders have given prior consent, under the RCF for working capital and for general corporate purposes. The Company may use these letters of credit, which can be obtained in various currencies, to secure, among other things, performance and bid bonds required in our ongoing business. Borrowings under the RCF bear interest at a rate equal to LIBOR plus a margin that depends on our leverage ratio. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.25%; at a leverage ratio between 2:1 and 2.25:1, the applicable margin will be 2.00%; and at a leverage ratio below 2:1, the applicable margin will be 1.75. At December 31, 2005, $14.6 million of letters of credit were issued under the RCF and the applicable margin was 2.25% per annum. In addition, the Company may be able to borrow an additional $250 million that would be secured by the same collateral that secures the Term Loan and borrowings under the RCF.

SHORT-TERM DEBT

Net short-term debt was $2.7 million as of December 31, 2005, relating to our Onshore business. As of December 31, 2004, net short-term debt was $2.0 million, of which $1.8 million related to the purchase of the seismic vessel Falcon Explorer.

COVENANTS

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

- our total leverage ratio may not exceed 3.50 to 1.0 in 2006, 3.25 to 1.0 in 2007 and 3.00 to 1.0 in 2008, and may not exceed 3.00 to 1.0 at the time of our proposed separation transaction,
- our consolidated interest coverage ratio (defined as the ratio of consolidated EBITDA less multi-client investments to consolidated interest expense) must be at least 3.0 to 1.0, and
- our consolidated fixed charge coverage ratio (defined as the ratio of consolidated EBITDA less multi-client investments to consolidated fixed charges) must be at least 1.3 to 1.0.

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

The Company is in compliance with the covenants in its loan and lease agreements as of December 31, 2005.

PLEDGED ASSETS

Certain seismic vessels and seismic equipment with a net book value of $45.4 million and $55.2 million at December 31, 2005 and 2004, respectively, are pledged as security under the Company's short-term and long-term debt. In addition, under the credit agreement established in December 2005, certain shares in material subsidiaries have been pledged as security.

LETTER OF CREDIT AND GUARANTEES

The Company had aggregate outstanding letters of credit and related types of guarantees, not reflected in the accompanying consolidated financial statements, of $32.7 million (including $14.6 million described above) and $30.1 million at December 31, 2005 and 2004, respectively.

NOTE 17 INTEREST EXPENSE

Interest expense consists of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Interest expense, gross	$ (98 234)	$ (112 272)	$ (17 245)	$ (92 504)
Interest on trust preferred securities	—	—	—	(8 536)
Interest capitalized in multi-client library (Note 10)	1 878	1 461	375	2 083
Total interest expense	$ (96 356)	$ (110 811)	$ (16 870)	$ (98 957)

NOTE 18 OTHER FINANCIAL ITEMS, NET

Other financial items, net, consist of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Interest income	$ 7 442	$ 4 840	$ 1 050	$ 4 467
Foreign currency gain (loss)	4 098	(8 024)	(5 208)	(4 286)
Sale of shares in Aqua Exploration Ltd.	—	1 500	—	—
Other	(5 622)	(9 177)	(106)	(1 653)
Total other financial items, net	$ 5 918	$ (10 861)	$ (4 264)	$ (1 472)

Other includes additional required rental payments relating to UK leases of $7.2 million for each of the years ended December 31, 2005 and 2004, $4.9 million for the two months ended December 31, 2003 and $1.5 million for the ten months ended October 31, 2003 (see Note 20).

NOTE 19 FINANCIAL INSTRUMENTS

FAIR VALUES OF FINANCIAL INSTRUMENTS

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

	December 31, 2005			December 31, 2004		
(In thousands of dollars)	Carrying Amounts	Notional Amounts	Fair Values	Carrying Amounts	Notional Amounts	Fair Values
Long-term debt (Note 16)	$ 943 866	$ —	$ 947 105	$ 1 103 018	$ —	$ 1 218 386
Derivatives:						
Forward exchange contracts (Note 13)	(7 234)	193 536	(7 234)	—	—	—
Interest rate swaps (cash flow hedging instruments) (Note 14)	(1 628)	425 000	(1 628)	—	—	—
Commodity derivatives	—	—	—	(2 583)	—	(2 583)

The fair values of the long-term debt instruments, forward exchange contracts and interest rate swaps are estimated using quotes obtained from dealers in such financial instruments or latest quoted prices at Bloomberg.

There is established under the indenture for the 8.28% Notes a debt service reserve fund, which was initially funded in an amount (approximately $10 million) equal to the maximum interest and sinking fund payment due on the 8.28% Notes on any payment date for such notes through December 1, 2010. Such additional amount has been invested in a funding agreement that serves as a source of funds that, together with charter hire payments made by a Company subsidiary under charters for the *Ramform Explorer* and the *Ramform Challenger* vessels, are used to make debt service payments on the 8.28% Notes. The amounts held in or payable into the debt service reserve fund will be used as part of the final payments on the 8.28% Notes. The Company classifies this amount as restricted cash (long-term) in its consolidated balance sheets ($10 million).

INTEREST RATE EXPOSURE

The Company holds interest rate derivative instruments. As of December 31, 2005, the Company had outstanding interest rate swap agreements in the aggregate notional amount of $433.6 million, of which $8.6 million either matured in January 2006 or were terminated in February 2006. As of December 31, 2005, we had entered into interest rate swaps relating to $425 million of the $850 million Term Loan and changed our interest rate exposure from floating to fixed interest rates for the $425 million notional amount. We account for these swaps as interest rate hedges. Under these interest rate swap agreements, the Company receives floating interest rate payments based on 3 month LIBOR and pays fixed interest rate payments. As to a notional amount of $150 million, a fixed rate of 4.84% will apply through December 2008. As to a notional amount of $275 million, an average fixed rate of 4.88% will apply through December 2010. The aggregate negative fair value of these interest rate swap agreements at December 31, 2005 was approximately $1.6 million and is reported as other long-term liabilities. The same amount, in accordance with SFAS 133, is recorded as a reduction in other comprehensive income as the effective portion of the designated and qualifying hedging instrument (the interest swaps).

FOREIGN EXCHANGE EXPOSURE

The Company is exposed to currency fluctuation due to a predominantly USD-based revenue stream, while the Company's expenses are incurred in various currencies. The larger expense currencies other than the USD are GBP and NOK. In 2005, the Company adopted a foreign currency hedging program by buying NOK and GBP on forward contracts. As of December 31, 2005, the Company had open forward contracts to buy GBP and NOK amounting to approximately $193.5 million with a negative fair value of $7.2 million reported as accrued expenses. As of December 31, 2004, the Company did not have any open forward exchange contracts. The currency forward contracts are not accounted for as hedges.

COMMODITY DERIVATIVES

Through February 2005, the Company operated in the worldwide crude oil market through its subsidiary Pertra AS, which was sold March 1, 2005 (see note 24). By reason of its ownership of Pertra, the Company had exposure to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2004 (combined) was 5 317 134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2005 and 2004, the Company did not have any outstanding derivative commodity instruments. In the first half of 2004, we sold forward 950 000 barrels of our 2004 second half production at an estimated average of $30.50 per barrel. Of the total amount sold forward, 250 000 barrels sold forward at an average price of $29.91 per barrel were not delivered at December 31, 2004, but were delivered in early January 2005. Estimated fair value of the contract at December 31, 2004 was a net liability of $2.6 million, which is included in accrued expenses in the consolidated balance sheets and in revenues products in the consolidated statements of operations, based on mark-to-market rates.

NOTE 20 COMMITMENTS AND CONTINGENCIES

LEASES

The Company has operating lease commitments expiring at various dates through 2015. The Company also has capital lease commitments, primarily for onshore-based seismic equipment, expiring at various dates through 2008. At December 31, 2005, future minimum payments related to non-cancelable operating and capital leases with lease terms in excess of one year are as follows:

(In thousands of dollars)	December 31, 2005 Operating Leases	December 31, 2005 Capital Leases
2006	$ 39 194	$ 23 094
2007	27 318	7 308
2008	26 889	6 869
2009	24 613	—
2010	12 597	—
Thereafter	27 852	—
Total	$ 158 463	$ 37 271
Imputed interest		(3 571)
Net present value of capital lease obligations		33 700
Current portion of capital lease obligations		(20 495)
Long-term portion of capital lease obligations		$ 13 205

The Company entered into a capital lease arrangement of $0.7 million for the year ended December 31, 2005, while there were no such new arrangements for the year ended December 31, 2004.

Future minimum payments related to non-cancelable operating leases reflect $8.2 million in sublease income for 2006, related to a time-charter of one FPSO shuttle tanker to a third party.

The future minimum payments under the Company's operating leases relate to the Company's operations as follows:

(In thousands of dollars)	December 31, 2005
Marine seismic and support vessels	$ 6 267
Onshore seismic equipment	75
FPSO shuttle and storage tankers	56 821
Buildings	94 341
Fixtures, furniture and fittings	959
Total	$ 158 463

Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above is charter hire for the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. The Company is required to charter the vessel for as long as *Ramform Banff* produces the Banff field, which could extend to 2014 depending on the customer/field operator. The maximum payment for the charter through 2014 is $97.8 million, of which only charter hire for the six month period ending June 30, 2006 is included in the table above.

Rental expense for operating leases, including leases with terms of less than one year, was $59.6 million and $59.4 million for the years ended December 31, 2005 and 2004, $12.2 million for the two months ended December 31, 2003 and $76.3 million for the ten months ended October 31, 2003. Rental expense for operating leases are net of sub-lease income related to time charter of FPSO shuttle tankers to a third party amounting to $10.0 million and $10.3 million for the years ended December 31, 2005 and 2004, $1.4 million for the two months ended December 31, 2003 and $16.6 million for the ten months ended October 31, 2003.

OTHER

The Company has contingencies resulting from litigation, other claims and commitments incidental to the ordinary course of business. Management believes that the probable resolution of such contingencies will not materially affect the financial position, results of operations or cash flows of the Company.

UK LEASES

The Company entered into capital leases from 1996 to 1998 relating to *Ramforms Challenger*, *Valiant*, *Viking*, *Victory* and *Vanguard*; the FPSO *Petrojarl Foinaven*; and the production equipment for the *Ramform Banff*. The terms for these leases ranged from 13-25 years. The Company has indemnified the lessors for the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities and for variations in actual interest rates from those assumed in the leases. There are no limits on either of these indemnities. Reference is also made to the description in Note 2 — UK Leases.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Although the UK Inland Revenue generally deferred for a period of time agreeing to the capital allowances claimed under such leases pending the outcome of a legal proceeding in which the Inland Revenue was challenging capital allowances associated with a defeased lease, in November 2004, the highest UK court of appeal ruled in favor of the taxpayer and rejected the position of the Inland Revenue. In connection with the adoption of fresh-start reporting on November 1, 2003 and before the November 2004 ruling, the Company recorded a liability of 16.7 million British pounds (approximately $28.3 million). The Company releases applicable portions of this liability if and when the Inland Revenue accepts the lessors' claims for capital allowances under each lease. In 2005 the Company released 9.4 million British pounds (approximately $17.2 million) of the liability, recorded as other operating (income) expense, net (see Note 5).

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

The leases are legally defeased because the Company has made up-front payments to independent third-party banks in consideration for which these banks have assumed liability to the lessor equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, the Company receives rental rebates. Conversely, if actual interest rates are less than the assumed interest rates, the Company pays rentals in excess of the defeased rental payments. Over the last several years, the actual interest rates have been below the assumed interest rates. Prior to November 1, 2003, the Company had deferred a portion of a deferred gain (see Note 2 — UK leases) representing the net present value of additional required rental payments as of the inception of each lease. Such deferred gain was amortized over the terms of the leases. Effective November 1, 2003, the Company adopted fresh-start reporting and recorded a liability equal to the fair value of the future additional required rental payments based on forward market rates for Sterling LIBOR and an 8% discount rate. This liability, which is amortized based on future rental payments, amounted to 30.5 million British pounds (approximately $51.6 million) at November 1, 2003, 24.6 million British pounds (approximately $47.2 million) at December 31, 2004 and 22.0 million British pounds (approximately $38.1 million) at December 31, 2005.

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

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

BRAZIL SERVICE TAX CLAIM

The Company has an ongoing appeal process in Brazil related to municipal services tax (“ISS”), whether the Company is actually liable for ISS taxes and, if it is liable for such taxes, to which municipality such taxes should be paid (municipalities levy ISS tax at different rates). The appeal relates to the period 1998 through 2001 and the potential additional exposure for this period is $8.5 million. The Company is subject to additional exposure for subsequent periods of up to $29.9 million (including potential interest and penalties). ISS is a service tax, and the Company’s primary view is that licensing of multi-client data should be treated as rental of an asset rather than a service, and therefore not subject to ISS. Management’s assessment is that it is reasonably possible, but not probable, that this liability will materialize. Thus no accrual has been recognized.

NOTE 21 INCOME TAXES

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

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Current taxes:				
Norwegian	$ 519	$ (5)	$ 394	$ 6 639
Foreign	10 343	20 761	1 558	15 373
Deferred taxes:				
Norwegian	—	24 534	(1 575)	2 025
Foreign	10 965	2 729	(4 226)	(3 943)
Total	$ 21 827	$ 48 019	$ (3 849)	$ 20 094
Classification in consolidated statements of operations:				
Income tax expense (benefit)	21 827	48 019	(3 849)	21 911
Fresh start adoption	—	—	—	(1 817)
Total income tax expense (benefit)	$ 21 827	$ 48 019	$ (3 849)	$ 20 094

The net expense (benefit) for the years ended December 31, 2005 and 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003 includes $224.7 million, $41.0 million, $3.1 million and $182.9 million, respectively, in valuation allowances related to deferred tax assets (see table below).

The net expense (benefit) for the years ended December 31, 2005 and 2004, and the ten months ended October 31, 2003 includes $(2.7) million, $9.5 million and $2.0 million, respectively, of provisions related to the resolution of uncertainties regarding outstanding tax issues. The total accrued amount related to contingent tax liabilities as of December 31, 2005 was $22.3 million, of which $3.1 million was recorded as income taxes payable and $19.2 million was recorded as other long-term liabilities. As of December 31, 2004, such amount totaled $29.9 million, of which $5.3 million was recorded in income taxes payable and $24.6 million was recorded as other long-term liabilities.

The Company evaluates the need for valuation allowances related to its deferred tax assets by considering the evidence regarding the ultimate realization of those recorded assets. A valuation allowance, by tax jurisdiction, is established when it is more likely than not that all or some portion of deferred tax assets will not be realized. During 2005, the Company concluded that certain valuation allowances are no longer necessary as available evidence, including recent accumulated profits and estimates of projected near term future taxable income, supported a more-likely-than-not conclusion that a portion of the related deferred tax assets will be realized. As a result the Company released a portion of its valuation allowance, resulting in recognition of deferred tax assets of $20.0 million as of December 31, 2005.

Changes in valuation allowance are as follows:

(In thousands of dollars)	Successor Company: Years Ended December 31, 2005	Successor Company: Years Ended December 31, 2004	Successor Company: Two Months Ended December 31, 2003	Predecessor Company: Ten Months Ended October 31, 2003
Balance at the beginning of the period	$ 405 285	$ 368 550	$ 365 439	$ 182 581
Current year additions	224 651	41 021	3 111	182 858
Decrease of valuation allowance from utilization and recognition of pre-reorganization deferred tax assets	(27 114)	(4 286)	—	—
Change related to other comprehensive income, sale of subsidiaries and minority interests	2 151	—	—	—
Balance at the end of the period	$ 604 973	$ 405 285	$ 368 550	$ 365 439

Current year additions to the valuation allowance relate to increases in tax losses carried forward and tax deductible temporary differences where the Company evaluated that it is more likely than not that the relevant deferred tax assets will not be recognized in future periods. Current year additions to the valuation allowance also include amounts related to deferred tax assets resulting from additional pre-reorganization tax loss carryforwards identified in 2005. There was a decrease of valuation allowance related to the utilization of tax benefits from pre-reorganization temporary differences and losses carried forward (for which a valuation allowance was provided at the date of reorganization) of $27.1 million, resulting in a corresponding decrease of intangible assets for the year ended December 31, 2005. The $27.1 million consisted of $7.1 million current year utilization and $20.0 million related to change in judgment about the estimated future utilization of deferred tax assets. The aggregate reduction to intangible assets consisted of reductions of $25.3 million to multi-client library, $1.3 million to other intangible assets and $0.5 million to other long-lived assets (see Notes 10, 11 and 12). Of the total valuation allowance as of December 31, 2005, $390.0 million relates to pre-reorganization amounts and will, if the related deferred tax assets are subsequently recognized, be allocated to reduce intangible assets existing at fresh-start (identified as multi-client library, other intangible assets and certain favorable lease contracts (included in other long-lived assets)) or directly to shareholders' equity if all intangible assets existing at fresh-start have been reduced to zero.

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

(In thousands of dollars)	Successor Company: Years Ended December 31, 2005	Successor Company: Years Ended December 31, 2004	Successor Company: Two Months Ended December 31, 2003	Predecessor Company: Ten Months Ended October 31, 2003
Income (loss) from continuing operations before income taxes, minority interest and cumulative effect of change in accounting principles:				
Norwegian	$ (103 101)	$ (125 179)	$ (16 755)	$ 623 654
Foreign	241 071	35 421	3 198	(46 052)
Total	137 970	(89 758)	(13 557)	577 602
Norwegian statutory rate	28%	28%	28%	28%
Expense (benefit) for income taxes at statutory rate	38 632	(25 132)	(3 796)	161 729
Increase (reduction) in income taxes from:				
Foreign earnings taxed at other than statutory rate	(4 415)	(7 612)	(440)	(2 057)
Petroleum surtax[a)]	(1 415)	12 343	(1 619)	5 908
Non-taxable gain on sale of subsidiary	(40 422)	—	—	—
Non-taxable gain on debt discharge	—	—	—	(351 078)
Other	5 655	3 047	—	—
Gain (loss) from local currency other than reporting currency	2 621	(2 578)	(1 495)	372
Current year realization of uncertain tax position not recognized in prior years	(82 556)	—	—	—
Non-creditable foreign taxes and other permanent items	27 728	26 930	390	22 362
Change in temporary differences to intangible assets due to utilization of pre-reorganization deferred tax assets (circle effect)	(8 760)	—	—	—
Deferred tax asset valuation allowance	84 759	41 021	3 111	182 858
Total income tax expense (benefit)	$ 21 827	$ 48 019	$ (3 849)	$ 20 094

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

Deferred tax assets and liabilities are summarized as follows:

	December 31,			
	2005		2004	
(In thousands of dollars)	Asset	Liability	Asset	Liability
Current assets and liabilities	$ (4 166)	$ 19 525	$ (3 036)	$ 1 038
Property, equipment and other long-lived assets	(137 822)	509	(23 384)	37 002
Tax losses carried forward	(447 799)	—	(262 458)	—
Deferred gain (loss)	(19 606)	22 527	(57 721)	32 971
Tax credits	(3 083)	—	(2 893)	—
Expenses deductible when paid	(47 503)	—	(84 853)	—
Other temporary differences	(6 003)	—	(6 072)	—
Total deferred tax (assets) liabilities before valuation allowance	(665 982)	42 561	(440 417)	71 011
Deferred tax asset valuation allowance	604 973		405 285	
Deferred tax (assets) liabilities	$ (61 009)	$ 42 561	$ (35 132)	$ 71 011
Net deferred tax (assets) liabilities — Norwegian		(20 000)		35 514
Net deferred tax (assets) liabilities — Foreign		1 552		365
Net deferred tax (assets) liabilities		$ (18 448)		$ 35 879
Classification in the consolidated balance sheets:				
Short-term deferred tax liabilities		$ 1 055		$ 761
Long-term deferred tax assets		(20 000)		—
Long-term deferred tax liabilities		497		35 118
Net deferred tax (assets) liabilities		$ (18 448)		$ 35 879

Tax losses carried forward in Norway of $1 166.0 million, in the UK of $282.2 million, and in Singapore, Brazil and Australia totaling $52.1 million can be carried forward indefinitely. U.S. tax losses carried forward of $63.9 million expire between 2019 and 2026.

The Company does not provide Norwegian taxes on unremitted earnings of certain international operations, which reflect full provision for non-Norwegian income taxes, as these earnings are expected to be reinvested outside of Norway indefinitely. The company has not calculated the tax effect associated with these unremitted earnings as it is not practicable to do so.

The Company has received a tax claim from the tax authority in Singapore relating to the years 1998 through 2002 based on the assertion that tax deductions for expenses related to investments in the multi-client data library would not be allowed. The possible additional exposure is $26.8 million, of which an assessment of $7.1 million has been issued for fiscal year 1998. Until 2003, the multi-client library was not automatically subject to tax allowances if classified as an intangible asset. The Company has filed tax returns claiming tax deductions for amortization of the multi-client library as included in the financial statements. The Company is currently preparing an appeal to the Ministry of Finance against the tax claim, which would assert that costs incurred when acquiring data under an exclusive license contract are tax deductible, while costs incurred when acquiring data under a non-exclusive multi-client license contract are not tax deductible. Management's assessment is that it is reasonably possible, but not probable, that the tax authority's view will prevail. Penalties of up to 17% of the $7.1 million that has already been assessed will accrue in 2006 if the Company does not pay the additional tax and is unsuccessful in claiming amortization.

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

NOTE 22 PENSION OBLIGATIONS

DEFINED BENEFIT PLANS

The Company has historically had defined benefit pension plans for substantially all of its Norwegian and UK employees, with eligibility determined by certain period-of-service requirements. In Norway these plans are generally funded through contributions to insurance companies. In the UK, the plans are funded through a separate pension trust. It is the Company's general practice to fund amounts to these defined benefit plans at rates that are sufficient to meet the applicable statutory requirements. As of January 1, 2005, a part of the Norwegian plans were settled eliminating future spouse and child-survivor benefits. Accrued benefits as of that date were settled with annuity contracts and employees eligible under these plans received a paid-up pension for earned funds covering the spouse and child portion up to December 31, 2004. In addition the Norwegian defined benefit plans were closed for further entries and new defined contribution plans established for new employees (see separate section below). At December 31, 2005, 955 employees were participating in the defined benefit plans.

Pension cost for disposed subsidiaries are included for the period up to the sales closing date.

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

Change in projected benefit obligations (PBO):

(In thousands of dollars)	December 31, 2005	December 31, 2004
Projected benefit obligations (PBO) at beginning of year	$ 117 796	$ 101 855
Service cost	9 445	10 198
Interest cost	5 540	5 145
Employee contributions	1 033	968
Payroll tax	24	178
Actuarial (gain) loss, net	11 166	(9 532)
Benefits paid	(1 382)	(1 212)
Exchange rate effects	(15 402)	10 196
Projected benefit obligations (PBO) at end of year	$ 128 220	$ 117 796

Change in pension plan assets:

(In thousands of dollars)	December 31, 2005	December 31, 2004
Fair value of plan assets at beginning of year	$ 71 565	$ 53 332
Adjustment at beginning of year	531	(1 214)
Return on plan assets	4 878	4 130
Employer contributions	9 848	8 383
Employee contributions	1 033	968
Benefits paid	(1 382)	(1 212)
Exchange rate effects	(8 237)	7 178
Fair value of plan assets at end of year	$ 78 236	$ 71 565

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

(In thousands of dollars)	December 31, 2005	December 31, 2004
Funded status	$ (49 984)	$ (46 232)
Unrecognized actuarial (gain) loss	9 892	(6 021)
Unrecognized prior service cost	(5 140)	—
Additional minimum liability	(211)	(219)
Net amount recognized as pension liability (Note 14)	$ (45 443)	$ (52 472)

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $111.4 million and $104.3 million as of December 31, 2005 and 2004, respectively.

Net periodic pension costs for the Company's defined benefit pension plans are summarized as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Service cost	$ 9 445	$ 10 198	$ 1 204	$ 7 145
Interest cost	5 540	5 145	1 207	3 247
Expected return on plan assets	(4 878)	(4 130)	(819)	(2 977)
Amortization of plan changes	(335)	—	—	—
Amortization of actuarial loss (gain)	(169)	16	(80)	403
Adjustment to actuarial (gain) loss, plan changes	1 080	—	—	—
Amortization of prior service cost	—	—	—	3
Amortization of transition obligation	—	—	—	17
Adjustment to minimum liability	—	198	—	—
Administration cost	105	99	—	—
Payroll tax	1 043	949	266	397
Net periodic pension cost	$ 11 831	$ 12 475	$ 1 778	$ 8 235

Plans in which the accumulated benefit obligation exceeds plan assets are as follows:

	December 31,	
(In thousands of dollars)	2005	2004
Projected benefit obligation (PBO)	$ 127 939	$ 112 727
Accumulated benefit obligation (ABO)	111 172	100 167
Fair value of plan assets	77 913	67 147

Assumptions used to determine net periodic pension costs:

	Years Ended December 31,					
	2005		2004		2003	
(In thousands of dollars)	Norway	UK	Norway	UK	Norway	UK
Discount rate	4.8%	5.3%	5.3%	5.3%	6.0%	5.3%
Return on plan assets	5.8%	7.5%	6.3%	7.5%	7.0%	7.5%
Compensation increase	3.2%	3.0%	3.0%	3.0%	3.0%	4.7%
Annual adjustment to pensions	3.2%	3.0%	3.0%	3.0%	3.0%	3.0%

Assumptions used to determine benefit obligations at end of years presented:

	December 31, 2005		December 31, 2004	
(In thousands of dollars)	Norway	UK	Norway	UK
Discount rate	4.3%	4.8%	5.3%	5.3%
Compensation increase	3.2%	3.2%	3.0%	3.0%

The discount rate assumptions used for calculating pensions reflect the rates at which the obligations could be effectively settled. Observable long-term rates on governmental bonds are used as a starting point and matched with the Company's expected cash flows under the Norwegian plans. Observable long-term rates on corporate bonds are used for the UK plans. The expected long-term rate of return on plan assets is based on historical experience and by evaluating input from the trustee managing the plan's assets.

The Company's pension plan asset allocation at December 31, 2005 and 2004, by asset category, are presented by major plan group as follows:

	2005		2004	
(In thousands of dollars)	Norway	UK	Norway	UK
Fair value of plan assets	$ 38 268	$ 39 968	$ 40 111	$ 31 454
Debt securities	62%	—	69%	—
Equity securities	23%	100%	16%	92%
Real estate	12%	—	12%	—
Other	3%	—	3%	8%
Total	100%	100%	100%	100%

Average target allocations for Norwegian plan assets are 15-30% in equity securities, 50-70% in debt securities, 10-15% in real estate and 3-10% in other. Maturities for the debt securities at December 31, 2005, range from two weeks to 28 years with a weighted average maturity of 4.6 years. Weighted average duration for the debt securities is 3.6 years.

Management of plan assets must comply with applicable laws and regulations in Norway and the UK where the Company provides defined benefits plans. Within constraints imposed by laws and regulations, and given the assumed pension obligations and future contribution rates, the majority of assets are managed actively to obtain a long-term rate of return that at least reflects the chosen investment risk.

The Company expects to contribute approximately $7.0 million to its defined benefit pension plans in 2006. Total pension benefit payments expected to be paid to participants from the plans are as follows:

(In thousands of dollars)	
2006	$ 1 166
2007	1 371
2008	1 545
2009	1 719
2010	1 320
2011 through 2015	15 374

DEFINED CONTRIBUTION PLANS

Substantially all employees not eligible for coverage under the defined benefit plans in Norway and the UK are eligible to participate in pension plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans.

As described above under "Defined Benefit Plans," as of January 1, 2005 the Company closed the Norwegian defined benefit plans for further entries and new defined contribution plans were established for new employees. The Company's contributions to these plans for the year ended December 31, 2005 totaled $0.2 million.

Under the Company's U.S. defined contribution 401(k) plan, essentially all U.S. employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 100% of compensation, subject to IRS and plan limitations, on a pre-tax basis, with a 2005 statutory cap of $14 000 ($18 000 for employees over 50 years). Employee pre-tax contributions are matched by the Company as follows: the first 3% are matched at 100% and the next 2% are matched at 50% of compensation. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $1.3 million and $1.2 million for the years ended December 31, 2005 and 2004, $0.2 million for the two months ended December 31, 2003 and $1.2 million for the ten months ended October 31, 2003. Contributions to the plan by employees for these periods were $3.3 million, $3.1 million, $0.6 million and $2.7 million, respectively.

Aggregate employer and employee contributions under the Company's other plans for the years ended December 31, 2005 and 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003, totaled $0.6 million and $0.3 million (2005), $0.8 million and $0.4 million (2004), $0.1 million and $0.1 million (two months 2003) and $2.1 million and $0.3 million (ten months 2003).

NOTE 23 SHARE BASED COMPENSATION PLANS

In connection with the restructuring of the Company in 2003, all shares in the Company were cancelled (see Notes 1 and 3 for additional information) and all agreements relating to share options for the Company's key employees and directors were cancelled. No new option agreements have been established since the restructuring. During the period in which the share-based compensation plan was active, the exercise price of each award equaled the market price of the Company's shares on the grant date. The vesting period for granted options ranged from approximately three years to approximately three and one-half years. Once vested, the exercisable life of the options was generally a two-year period, with certain options granted during 2000 and thereafter exercisable over a three-year period. The Company used the intrinsic value method to account for this stock-based employee compensation.

A summary of the status of the Company's share-based compensation plans as of December 31, 2003 is summarized as follows:

	December 31, 2003	
	Options	Weighted Average Exercise Price
Outstanding at beginning of year	4 973.5	NOK 135
Forfeited/cancelled	(4 973.5)	NOK 135
Outstanding at December 31, 2003	—	—

If the compensation cost for the share-based compensation plans had been determined based on the fair values of the options awarded at the grant dates, consistent with the provisions of SFAS 123, the net income (loss) and earnings (loss) per share would have been affected on a pro forma basis as indicated below:

	Predecessor Company
(In thousands of dollars, except for share amounts)	Ten Months Ended October 31, 2003
Net income, as reported	$ 557 045
Deduct: Total share-based compensation expense determined under the fair value based method for all awards, net of related tax effect	(5 105)
Pro forma, net income	$ 551 940
Net income per share:	
Basic and diluted — as reported	$ 5.39
Basic and diluted — pro forma	$ 5.34

NOTE 24 ACQUISITIONS AND DISPOSITIONS

In 2002, the Company sold its Production Services (formerly Atlantic Power Group) subsidiary to Petrofac Limited. The Company is eligible to receive an additional consideration of $2.5 million upon the occurrence of certain contingent events through 2010.

In February 2003, the Company sold its Atlantis oil and gas activities to Sinochem and received proceeds and reimbursements aggregating $59.2 million. The Company was entitled to receive up to $25.0 million in additional, contingent proceeds, which agreement was amended in June 2005. In accordance with the amended agreement, the Company may receive a maximum of $10.0 million in contingent proceeds upon the occurrence of certain contingent events, which currently has not been recognized.

In December 2003, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. for a deferred compensation of approximately $1.8 million, payable in 2004 through 2007, for which payments were received in December 2005 and 2004. The Company may also receive additional contingent proceeds based on performance of the company through 2006. As of December 31, 2005, the Company had not received any such contingent proceeds. The Company recognized no net gain or loss on the sale of Tigress.

In March 2005, the Company sold its wholly owned oil and natural gas subsidiary Pertra AS to Talisman Energy (UK) Ltd. for an initial sales price of approximately $155 million. Pertra AS has been renamed Talisman Production Norge AS. The Company recognized a $149.8 million gain from the sale, including the $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg*, recognized as net gain on sale of subsidiaries. As part of the transaction, the Company is entitled to receive additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006, we received $8.1 million, representing the 2005 portion of the contingent consideration. The Company accrued this amount in December 2005 and recognized the amount as additional gain on the 2005 sale (see Note 4). The Company also granted an option enabling Talisman to change the termination clause with respect to PL038. The option expired on February 1, 2006 without being exercised. Assets and liabilities relating to Pertra as of December 31, 2004 are shown below, while the results of operations and capital expenditures for the periods presented up to March 1, 2005 are presented as a separate segment in our consolidated statements of operations (see Note 27). The operations of Pertra are not presented as discontinued operations due to continuing involvement through the charter of *Petrojarl Varg*.

In August 2005, the Company entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS to Reservoir Consultants Holding AS ("RCH"), which is controlled by a group of former PGS employees. RCH has the option to sell the shares back to the Company for an amount equal to the consideration (approximately $0.5 million), which option expires 12 months from completion date (August 31, 2005). The Company has recorded an estimated loss of $1.5 million for this transaction, recognized in net gain on sale of subsidiaries (see Note 4.) In addition the Company recorded assets and liabilities of business transferred under the contractual arrangement aggregating $3.5 million gross. Such assets and liabilities are recognized in other current assets and accrued expenses (see Notes 8 and 13).

The results of operations, net assets and cash flows for Tigress have been presented as discontinued operations, and are summarized as follows for the years presented:

	Successor Company	Predecessor Company
(In thousands of dollars)	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Revenues	$ 137	$ 1 107
Operating expenses before depreciation, amortization, impairment and other operating (income) expense, net	(264)	(2 433)
Depreciation and amortization	—	(707)
Other operating (income) expense, net	—	(512)
Total operating expenses	(264)	(3 652)
Operating profit (loss)	(127)	(2 545)
Interest expense and other financial items, net	24	(1 237)
Income (loss) before income taxes	$ (103)	$ (3 782)
Capital expenditures of discontinued operations	$ —	$ 118

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

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Income (loss) from discontinued operations before income taxes	$ —	$ —	$ (103)	$ (3 782)
Loss on disposal	—	—	(32)	—
Additional proceeds	500	3 048	—	1 500
Loss from discontinued operations, net of tax	$ 500	$ 3 048	$ (135)	$ (2 282)

Operating expenses relating to discontinued operations includes corporate management fees based on actual charges to these entities. For continuing operations, such fees are presented in the segment for Reservoir/ Shared Services/ Corporate (see Note 27). Allocation of interest expense to discontinued operations is based on actual interest charged to the respective entities.

The operations of Pertra are presented as a separate segment in our consolidated statements of operations (see Note 27). Assets and liabilities relating to Pertra as of December 31, 2004 were as follows:

	December 31, 2004
(In thousands of dollars)	Pertra
Cash and cash equivalents	$ 13 423
Accounts receivable, net	7 406
Other current assets	15 916
Property and equipment, net	937
Oil and natural gas assets, net	70 940
Other long-lived assets	12 024
Total assets	$ 120 646
Accounts payable	$ 1 624
Accrued expenses	8 720
Deferred tax liabilities, current	761
Other long-term liabilities	39 942
Deferred tax liabilities, long-term	34 752
Total liabilities	$ 85 799

SUBSEQUENT EVENTS

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

As described above, the Company may receive $10 million in additional contingent proceeds, upon the occurrence of certain contingent events, from the sale of Atlantis in 2003. At December 31, 2005, the Company had not accrued for these proceeds. In March 2006, the Company received confirmation of the occurrence of certain of these events that entitle the Company to receive $6 million, of which $3 million was received in March 2006.

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

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

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

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

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

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

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

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

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

NOTE 25 RELATED PARTY TRANSACTIONS

At December 31, 2003 the Company owned 50% of the shares in Geo Explorer AS and had one vessel on charter from that company. The Company also held 100% of the shares in Walther Herwig AS (until December 11, 2003, the Company held 50% of the shares, but increased its shares as Walter Herwig AS was de-merged) and chartered three vessels from that company in 2003. Total lease expense recognized during the two months ended December 31, 2003 and the ten months ended October 31, 2003 on these vessels was $1.1 million and $6.4 million, respectively. There were no lease expenses for the years ended December 31, 2005 and 2004.

As of December 31, 2005, the chairperson of the Board, Jens Ulltveit-Moe, through Umoe AS, controlled a total of 3 037 332 shares in PGS. Jens Ulltveit-Moe also has a majority ownership interest in Knutsen OAS Shipping AS ("Knutsen"). Knutsen is chartering the MT *Nordic Svenita* and was also chartering the MT *Nordic Yukon* up to 2003 and paid $10.0 million, $10.3 million and $20.1 million to the Company under time charter contracts for the vessels in 2005, 2004 and 2003, respectively. The Company charters the vessels from an independent third party. The vessels were chartered by the Company to provide shuttle services for the Banff field, but in 2001 were chartered to Knutsen on terms approximating the Company's terms under the third-party lease, due to low production on the Banff field. The vessel MT *Nordic Yukon* was redelivered by PGS to the vessel owner in November 2003. In addition, PGS has a contract of affreightment with Knutsen for transporting crude oil relating to the Banff field and paid $1.2 million, $0.7 million and $2.4 million to Knutsen under this contract in 2005, 2004 and 2003, respectively. Mr. Ulltveit-Moe was also the chairperson of Unitor ASA until August 2005, a company that from time to time provides the Company with equipment for its vessels.

SUBSEQUENT EVENT

In January 2006 the Company entered into an agreement to purchase the shuttle tanker MT *Rita Knutsen* for $35 million from Knutsen OAS Shipping AS. The transaction was completed March 9, 2006. The Company considers the vessel to be a possible FPSO solution for several upcoming projects, and the Company intends to begin a conversion when a firm contract for the ship is secured. The vessel will be operated by Knutsen OAS Shipping AS under a bareboat charter agreement until a decision to start conversion is made. Jens Ulltveit-Moe did not participate in any Board discussions relating to this transaction.

NOTE 26 INVESTMENTS IN ASSOCIATED COMPANIES

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

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Corporations and limited partnerships:				
Geo Explorer AS	$ (2)	$ 26	$ 119	$ 1 425
Atlantic Explorer (IoM) Ltd.	(5)	(80)	—	—
Ikdam Production, SA	243	722	81	162
Triumph Petroleum	—	—	—	(813)
General partnerships	40	—	—	—
Total	$ 276	$ 668	$ 200	$ 774

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

(In thousands of dollars)	Book Value December 31, 2004	Share of Income 2005	Paid-In Capital/ (Dividends) 2005	Equity Transactions 2005[a)]	Book Value December 31, 2005	Ownership Percent As of December 31, 2005
Corporations and limited partnerships:						
Ikdam Production, SA	$ 5 411	$ 243	$ —	$ (1)	$ 5 653	40.0%
Geo Explorer AS	182	(2)	—	(15)	165	50.0%
Atlantic Explorer (IoM) Ltd.	32	(5)	—	(3)	24	50.0%
Valiant Intern. Petroleum Ltd.	—	—	68	—	68	24.6%
General partnerships	95	40	(66)	(44)	25	
Total	$ 5 720	$ 276	$ 2	$ (63)	$ 5 935	

a) Includes foreign currency translation differences.

NOTE 27 SEGMENT AND GEOGRAPHIC INFORMATION

The Company, after the sale of Pertra AS in March 2005, manages its business in three segments as follows:

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

Pertra AS, a small oil and natural gas company, was sold March, 2005 (see Notes 4 and 24). Revenues and expenses, assets and liabilities are included in the consolidated statements through February 2005 and in the comparative numbers for the years presented. The operations of Pertra are not presented as discontinued operations due to continuing involvement through the lease of *Petrojarl Varg*.

The Company manages its Marine Geophysical segment from Lysaker, Norway, its Onshore segment from Houston, Texas, and its Production segment from Trondheim, Norway.

The principal markets for the Production segment are the UK and Norway. The Marine Geophysical and Onshore segments serve a worldwide market. Customers for all segments are primarily composed of major multinational, independent and national or state-owned oil companies. Corporate overhead has been presented under Reservoir/ Shared Services/ Corporate. Significant charges, which do not relate specifically to the operations of any one segment, such as debt refinancing and restructuring costs, are also presented as Reservoir/ Shared Services/ Corporate. Information related to discontinued operations during any period presented has been separately aggregated. Affiliated sales are made at prices that approximate market value. Interest and income tax expense are not included in the measure of segment performance.

REVENUES BY SEGMENT

The table below presents our mix of revenues for the periods presented:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Marine Geophysical:				
Contract	$ 424 192	$ 297 749	$ 48 273	$ 302 451
Multi-client pre-funding	40 006	30 535	6 510	43 187
Multi-client late sales	218 781	203 397	36 786	123 435
Other	41 703	39 124	7 813	31 040
Total Marine Geophysical	724 682	570 805	99 382	500 113
Onshore:				
Contract	122 415	110 288	18 442	106 324
Multi-client pre-funding	16 148	12 761	1 807	14 636
Multi-client late sales	13 976	10 112	1 210	8 005
Total Onshore	152 539	133 161	21 459	128 965
Production:				
Petrojarl I	53 394	61 303	11 086	58 529
Petrojarl Foinaven	89 191	96 595	18 726	93 373
Ramform Banff	46 483	51 509	6 572	38 616
Petrojarl Varg	89 920	87 133	8 604	59 191
Other	1 689	1 662	241	349
Total Production	280 677	298 202	45 229	250 058
Reservoir/ Shared Services/ Corporate	19 418	20 852	4 957	16 243
Elimination inter-segment revenues	(17 732)	(77 686)	(8 200)	(45 612)
Total revenues services	1 159 584	945 334	162 827	849 767
Revenues products — Pertra	36 742	184 134	9 544	112 097
Total revenues	$ 1 196 326	$ 1 129 468	$ 172 371	$ 961 864

Additional segment information for the periods presented is summarized as follows:

(In thousands of dollars)	Marine Geo-physical	Onshore	Produc-tion	Pertra	Res-ervoir/ Shared Services/ Corpo-rate	Elimina-tion of Inter-Segment Items	Total
Depreciation and amortization:							
2005 (Successor)	$ 172 349	$ 31 665	$ 44 064	$ 6 710	$ 4 567	$ —	$ 259 355
2004 (Successor)	241 712	39 885	44 561	38 965	3 239	—	368 362
2003 (Successor — two months)	39 351	6 224	8 112	743	1 269	—	55 699
2003 (Predecessor — ten months)	191 215	29 425	43 418	30 826	6 692	—	301 576
Segment operating profit:							
2005 (Successor)	$ 150 229	$ (9 803)	$ 43 491	$ (1 507)	$ (25 789)	$ 924	$ 157 545
2004 (Successor)	(34 980)	(4 535)	77 769	28 120	(20 986)	(1 593)	43 795
2003 (Successor — two months)	1 772	1 778	11 878	(3 198)	(476)	—	11 754
2003 (Predecessor — ten months)	41 782	19 741	66 876	17 236	(19 475)	—	126 160
Impairment of long-lived assets:							
2005 (Successor)	$ 4 575	$ —	$ —	$ —	$ —	$ —	$ 4 575
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	89 598	5 085	328	—	—	—	95 011
Net (gain) on sale of subsidiaries:							
2005 (Successor)	$ —	$ —	$ —	$ —	$ (156 382)	$ —	$ (156 382)
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	—	—	—	—	—	—	—
Other operating (income) expense, net:							
2005 (Successor)	$ (8 847)	$ —	—	$ —	$ (17 248)	$ —	$ (26 095)
2004 (Successor)	(13)	9	—	—	8 116	—	8 112
2003 (Successor — two months)	1 189	38	—	—	(175)	—	1 052
2003 (Predecessor — ten months)	8 107	266	—	—	12 951	—	21 324
Operating profit:							
2005 (Successor)	$ 154 501	$ (9 803)	$ 43 491	$ (1 507)	$ 147 841	$ 924	$ 335 447
2004 (Successor)	(34 967)	(4 544)	77 769	28 120	(29 102)	(1 593)	35 683
2003 (Successor — two months)	583	1 740	11 878	(3 198)	(301)	—	10 702
2003 (Predecessor — ten months)	(55 923)	14 390	66 548	17 236	(32 426)	—	9 825
Income (loss) from discontinued operations, net of tax:[a]							
2005 (Successor)	$ —	$ —	$ 500	$ —	$ —	$ —	$ 500
2004 (Successor)	—	—	3 048	—	—	—	3 048
2003 (Successor — two months)	(135)	—	—	—	—	—	(135)
2003 (Predecessor — ten months)	(3 782)	—	1 500	—	—	—	(2 282)
Cumulative effect of change in accounting principles, net of tax							
2005 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	(779)	—	3 168	—	—	—	2 389
Investment in associated companies:							
December 31, 2005	$ 278	$ —	$ 5 653	$ —	$ 4	$ —	$ 5 935
December 31, 2004	235	—	5 411	—	74	—	5 720
Total assets:							
December 31, 2005	$ 797 316	$ 98 823	$ 676 337	$ —	$ 145 096	$ —	$ 1 717 572
December 31, 2004	795 102	90 451	710 521	120 646	135 433	—	1 852 153

(Continued) (In thousands of dollars)	Marine Geo-physical	Onshore	Produc-tion	Pertra	Res-ervoir/ Shared Services/ Corpo-rate	Elimina-tion of Inter-Segment Items	Total
Additions to long-lived tangible assets:[b]							
2005 (Successor)	$ 118 442	$ 21 055	$ 11	$ 103	$ 6 629	$ (83)	$ 146 157
2004 (Successor)	87 742	10 817	988	84 991	5 088	(114)	189 512
2003 (Successor — two months)	13 715	5 182	1 662	4 424	463	—	25 446
2003 (Predecessor — ten months)	71 299	21 965	(1 147)	29 741	1 349	—	123 207
Capital expenditures on discontinued operations:[a]							
2005 (Successor)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
2004 (Successor)	—	—	—	—	—	—	—
2003 (Successor — two months)	—	—	—	—	—	—	—
2003 (Predecessor — ten months)	118	—	—	—	—	—	118

a) Income (loss) from discontinued operations, net of tax, and capital expenditures on discontinued operations, included in segment data for Marine Geophysical and Production relates to Tigress and Production Services, respectively.

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

Reconciliation of segment operating profit, presented in the table above, to income (loss) before income tax expense (benefit) and minority interest, is as follows:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Segment operating profit	$ 157 545	$ 43 795	$ 11 754	$ 126 160
Other segment allocated amounts (as presented in the table above):				
Impairment of long-lived assets	4 575	—	—	95 011
Net (gain) on sale of subsidiaries	(156 382)	—	—	—
Other operating (income) expense net	(26 095)	8 112	1 052	21 324
Operating profit	335 447	35 683	10 702	9 825
Unallocated amounts:				
Income from associated companies	276	668	200	774
Interest expense	(96 356)	(110 811)	(16 870)	(98 957)
Debt redemption and refinancing costs	(107 315)	—	—	—
Other financial items net	5 918	(10 861)	(4 264)	(1 472)
Gain on debt discharge	—	—	—	1 253 851
Fresh-start adoption	—	—	—	(532 268)
Cost of reorganization	—	(3 498)	(3 325)	(52 334)
Income (loss) before income tax expense (benefit) and minority interest	$ 137 970	$ (88 819)	$ (13 557)	$ 579 419

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

Information by geographic region is summarized as follows:

(In thousands of dollars)	Americas	UK	Norway	Asia/ Pacific	Africa	Middle East/ Other	Elimination of Inter-Segment Items	Total
Revenue, external customers:								
2005 (Successor)	$ 311 496	$ 175 440	$ 306 158	$ 199 107	$ 139 317	$ 64 808	$ —	$ 1 196 326
2004 (Successor)	267 054	191 745	336 949	191 703	112 503	29 514	—	1 129 468
2003 (Successor — two months)	49 164	30 743	33 087	35 175	20 784	3 418	—	172 371
2003 (Predecessor — ten months)	270 095	181 595	235 663	82 980	124 601	66 930	—	961 864
Revenue, includes inter- segment:								
2005 (Successor)	$ 312 394	$ 176 053	$ 309 349	$ 199 826	$ 139 679	$ 65 186	$ (6 161)	$ 1 196 326
2004 (Successor)	267 054	194 712	343 736	191 703	112 503	29 514	(9 754)	1 129 468
2003 (Successor — two months)	49 164	31 067	35 429	35 175	20 784	3 418	(2 666)	172 371
2003 (Predecessor — ten months)	270 095	183 371	238 543	82 980	124 601	66 930	(4 656)	961 864
Total assets:								
December 31, 2005	$ 302 774	$ 940 263	$ 380 898	$ 73 801	$ 10 663	$ 9 173	$ —	$ 1 717 572
December 31, 2004	343 484	927 172	469 675	79 873	21 211	10 738	—	1 852 153
Capital expenditures (cash):								
2005 (Successor)	$ 19 183	$ 63 679	$ 5 195	$ 1 579	$ —	$ 854	$ —	$ 90 490
2004 (Successor)	7 955	40 812	96 813	1 975	—	817	—	148 372
2003 (Successor — two months)	5 464	1 005	9 294	222	—	—	—	15 985
2003 (Predecessor — ten months)	6 261	6 155	27 952	136	—	1 561	—	42 065

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2005, 2004 and 2003.

For the years ended December 31, 2005, 2004 and 2003, customers exceeding 10% of the Company's total revenue were as follows (the table shows percentage of revenues accounted for by each of such customers, and the segments that had sales to the respective customers are marked with X):

	2005		2004		2003		
	13%	10%	25%	10%	19%	12%	10%
Segments serving customer (each % in each year represents a separate customer):							
Marine Geophysical	X	X	X	X	X	X	X
Onshore		X					X
Production	X	X	X	X	X	X	
Pertra	X		X		X		
Reservoir/ Shared Services/ Corporate	X		X		X		

In certain of the regions where the Company operates, a significant share of its employees is organized in labor unions. Similarly the Company's operations in certain regions are members of employer unions. Therefore, the Company may be affected by labor conflicts involving such labor and employer unions.

NOTE 28 SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid during the year includes payments for:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Interest, net of capitalized interest	$ 91 724	$ 106 731	$ 19 619	$ 120 162
UK lease, additional required rental payments (Note 20)	7 180	7 196	4 953	1 473
Income taxes	14 572	29 751	4 951	8 145

The Company entered into capital lease agreements for new equipment aggregating $0.7 million for the year ended December 31, 2005 and $0.6 million for the ten months ended October 31, 2003. There were no new capital lease agreements during the year ended December 31, 2004 or the two months ended December 31, 2003.

NOTE 29 SUMMARIZED FINANCIAL INFORMATION FOR SUBSIDIARIES WITH DEBT SECURITIES

PGS Geophysical AS, a Norwegian corporation, is a wholly owned subsidiary of the Company. PGS Geophysical AS is the largest geophysical services company within the PGS group of companies. PGS Geophysical AS is also the lessee of the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. PGS ASA (parent company) has fully and unconditionally guaranteed PGS Geophysical AS charter obligations in connection with certain debt securities issued in order to finance the purchase of these vessels. Summarized financial information for PGS Geophysical AS and its consolidated subsidiaries is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with U.S. GAAP. Separate financial statements and other disclosures with respect to PGS Geophysical AS are omitted because the information contained therein, in light of the information contained in the consolidated financial statements of the Company, would not be material.

The PGS Geophysical AS summarized financial information consists of the following:

	Successor Company			Predecessor Company
	Years Ended December 31,			
(In thousands of dollars)	2005	2004	Two Months Ended December 31, 2003	Ten Months Ended October 31, 2003
Income Statement Data:				
Revenue	$ 332 190	$ 257 609	$ 17 610	$ 244 605
Operating profit (loss)	18 423	(4 761)	(26 009)	(4 238)
Net income (loss)	6 376	(22 868)	(12 671)	(6 752)
Balance Sheet Data:				
Current assets	$ 90 433	$ 116 910	$ 99 453	
Non-current assets	185 535	190 874	148 951	
Current liabilities	96 168	56 573	84 523	
Non-current liabilities	142 686	327 199	408 479	
Equity (deficit)	37 114	(75 988)	(244 598)	

Both Oslo Explorer PLC ("Explorer") and Oslo Challenger PLC ("Challenger"), Isle of Man public limited companies, are wholly owned subsidiaries of the Company, purchased in April 1997. Explorer and Challenger own the *Ramform Explorer* and the *Ramform Challenger*, respectively, and lease these vessels to PGS Geophysical AS pursuant to long-term bareboat charters. Explorer and Challenger are jointly and severally liable under the 8.28% First Preferred Mortgage Notes (see Note 16), in an original principal amount of $165.7 million, which were issued to finance the purchase of the *Ramform Explorer* and the *Ramform Challenger*. Summarized financial information for each of Explorer and Challenger is presented below. This information was derived from the financial statements prepared on a stand-alone basis in conformity with U.S. GAAP. Separate financial statements and other disclosures with respect to Explorer and Challenger are omitted because the information, in light of the information contained in the consolidated financial statements of the Company, would not be material.

The Oslo Explorer PLC and Oslo Challenger PLC summarized financial information consists of the following:

	Successor Company						Predecessor Company	
	Years Ended December 31,							
	2005		2004		Two Months Ended December 31, 2003		Ten Months Ended October 31, 2003	
(In thousands of dollars)	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger	Explorer	Challenger
Income Statement Data:								
Revenue	$ 5 064	$ 5 455	$ 5 491	$ 5 858	$ 1 164	$ 1 169	$ 5 820	$ 5 844
Operating profit	4 883	5 273	5 346	5 713	(6 732)	(4 562)	5 693	5 717
Net income (loss)	766	1 157	799	1 166	(7 557)	(5 387)	1 566	1 590
Balance Sheet Data:								
Current assets	$ —	$ —	$ —	$ —	$ —	$ —		
Non-current assets	51 375	54 101	56 866	59 200	61 192	63 158		
Current liabilities	6 280	6 280	6 611	6 611	6 252	6 251		
Non-current liabilities	38 211	38 213	44 137	44 138	49 621	49 622		
Equity	6 884	9 608	6 118	8 451	5 319	7 285		

NOTE 30 SUPPLEMENTAL INFORMATION — OIL AND GAS RESERVES AND COSTS (UNAUDITED)

In March 2005, the Company sold its oil and natural gas subsidiary Pertra AS to Talisman Energy (UK) Ltd. (see Note 24). Pertra did not meet the significant activities requirements for the year ended December 31, 2005. The Company meets the significant activities requirements for the year ended December 31, 2004, the two months ended December 31, 2003 and the ten months ended October 31, 2003. However, it is not considered material to the disclosure to separately present the changes in reserves or the changes in Standardized Measure for the Predecessor and Successor periods during the years ended December 31, 2004 and 2003.

Pertra had proved oil reserves associated with its 70% interest in PL 038 on the NCS. The Company, through its Marine Geophysical segment, also owns some small overriding royalty interests in oil and natural gas production offshore in the US Gulf of Mexico. The supplemental financial and oil and natural gas reserve information and standardized measure of future cash flows from proved reserves are presented for Pertra only. The overriding royalties financial results and oil and natural reserves are not considered material for disclosure. In addition, Pertra employed a Company FPSO to produce oil from PL 038. The revenues and expenses from this FPSO are eliminated in consolidation, but the expenses are presented gross for this supplemental presentation. As a result, the oil and natural gas results in this supplemental disclosure will not match the results in the consolidated statements of operations.

FINANCIAL RESULTS RELATED TO OIL AND NATURAL GAS ACTIVITIES

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

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

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

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

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

(In thousands of dollars)	December 31, 2004
Capitalized Costs:	
Proved properties	$ 106 604
Unproved properties	4 000
Accumulated depreciation, depletion and amortization	(39 664)
Net	70 940

As a supplemental disclosure, under the full cost method the depletion, depreciation and amortization rate for the Predecessor for the ten months ended October 31, 2003 was $8.65 per barrel of oil produced.

Following is a summary of costs incurred in oil and natural gas exploration and development activities:

	Successor Company		Predecessor Company
(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 was prepared by the Company's engineers in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The estimates were reviewed by an independent reservoir engineering consultant. All of Pertra's proved reserves are located in the Norwegian North Sea. The reserve estimates as of December 31, 2004 utilize oil prices of $40.24 per barrel (reflecting adjustments for oil quality). The Company's actual average sale price for oil produced in 2004 was $35.11 per barrel, compared to $29.37 per barrel in 2003.

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

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

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

Estimated Quantities of Reserves (Unaudited)

(In thousands of dollars)	December 31, 2004
CRUDE OIL:	
Proved Reserves:	
Beginning of the year	7 818
Extensions and discoveries	2 976
Revisions of previous estimates	—
Production	(5 317)
End of year	5 477
Proved Developed Reserves:	
Beginning of year	2 114
End of year	5 477

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

(In thousands of dollars)	December 31, 2004
Future cash inflows	$ 220 440
Future production costs	108 253
Future development costs	—
Future abandonment costs	47 391
Future income taxes	51 762
Future net cash flows	13 034
Discount at 10% per annum	(2 288)
Standardized Measure	$ 15 322

Changes in Standardized Measure (Unaudited)

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

AUDITOR'S REPORT

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of

PETROLEUM GEO-SERVICES ASA:

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

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

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

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

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

/s/ Ernst & Young AS

Oslo, Norway

April 4, 2006

N GAAP ANNUAL REPORT

BOARD OF DIRECTORS' REPORT

In 2005, PGS substantially improved its financial and strategic flexibility through strong cash flow, debt repayment and refinancing. Our operating performance improved markedly reinforced by a strong upward trend in worldwide oil and gas exploration and production spending. We further improved our strong HSE&Q performance in 2005.

With the sale of the oil and gas subsidiary Pertra in March 2005, we became a dedicated oil service company. On March 27, 2006, our Board of Directors resolved to sign a demerger plan to separate our geophysical and production businesses into two independently listed companies, and call for an extraordinary general meeting to approve the transaction.

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

We managed in 2005 our business in three segments as follows:

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

In addition, we owned Pertra AS, a small oil and natural gas company which represented a separate segment, until it was sold to Talisman March 2005.

BUSINESS HEADLINES 2005

In 2005 we:

- Improved our strong safety performance
- Achieved a strong full year cash flow and a significant debt reduction
- Significantly improved our marine seismic contract operating profit margins
- Increased marine multi-client late sales by 6% compared to 2004, despite three years of low multi-client investments
- Sold our oil and natural gas subsidiary Pertra
- Repaid from available cash or refinanced the majority of our debt to provide greater operating flexibility and lower borrowing costs

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

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

MARKETS AND MAIN BUSINESSES

Marine Geophysical

We are one of four major global participants in the marine 3D market, with a market share of approximately 30%. Our streamer acquisition fleet, totaling ten 3D vessels at year end 2005, with the six Ramform vessels in the high capacity segment, is the most modern in the industry.

The marine 3D market experienced a strong improvement in 2005 driven by increased demand for seismic from oil and gas companies. The margin we realized on contract seismic improved throughout the year at the same time as the backlog increased. At the end of 2005, our marine order backlog was approximately $365 million, compared to approximately $170 million at December 31, 2004.

Contract seismic continued to dominate our activity in 2005, although the investments in new multi-client data increased from the low levels seen in 2004. Pre-funding of new multi-client investments continued at a high level and late sales for the year came in significantly higher than anticipated at the beginning of 2005.

Onshore

In the market for onshore seismic services we are one of the larger worldwide operators. The onshore segment remains price competitive because a number of competitors have added capacity, and additional companies have entered the international seismic market.

In 2005, PGS Onshore entered the markets in North and West Africa by winning new contracts. The associated mobilization and start-up costs, however, weakened the operating results for the year. PGS Onshore continued to invest in its multi-client library onshore U.S. in 2005, but as in 2004, the majority of the crews performed contract work.

Production

We are 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 2005 with high operating regularity.

Ramform Banff is producing the Banff field, operated by Canadian Natural Resources (CNR), in the UK sector of the North Sea. The compensation is based on production levels, but also contains a minimum day rate provision of $126 800 per day. In 2005 the Kyle field was tied in to *Ramform Banff*. We expect production to continue on the Banff field until 2014.

Petrojarl I is producing the Glitne field, operated by Statoil, in the Norwegian sector of the North Sea. The producing life of the Glitne field may extend beyond 2008.

Petrojarl Varg is producing the Varg field (in PL038) operated by Talisman, in the Norwegian sector of the North Sea. The FPSO could become available for redeployment in 2008.

Petrojarl Foinaven is producing the Foinaven field, operated by BP, west of Shetland. The vessel is expected to produce the field beyond 2010.

FINANCIAL RESULTS

Total revenues for 2005 were $1 194.0 million compared to $1 135.5 million in 2004, an increase of 5%. Pertra contributed with $34.2 million of revenues and an operating loss of $4.2 million in 2005, compared to $186.7 million of revenues and an operating profit of $30.7 million in 2004.

Marine Geophysical 2005 revenues totaled $724.9 million, an increase of $150.7 million, or 26%, from 2004. Revenues from contract seismic acquisition increased $125.8 million from $298.6 million in 2004 to $424.4 million in 2005, primarily due to a stronger marine seismic market and strong operating performance. Multi-client late sales increased by $12.8 million, or 6%, to $218.8 million in 2005. Marine Geophysical increased its acquisition of multi-client data with $14.4 million or 45% to $46.2 million in 2005. Revenues from multi-client pre-funding increased by $9.5 million, or 31%, from $30.5 million in 2004 to $40.0 million in 2005. Pre-funding as a percentage of cash investments in multi-client data decreased to 87% in 2005 compared to 96% in 2004. In 2005 the fleet allocation (active vessel time) between contract and multi-client data acquisition was approximately 91%/9% compared to approximately 88%/12% in 2004.

Onshore revenues for 2005 totaled $152.5 million, an increase of $19.3 million or 14% from 2004. Onshore started up a new project in Nigeria in 2005, while the activity in domestic U.S. continued with three crews.

Revenues for Production totaled $280.7 million (including affiliate sales to Pertra) in 2005, which was $17.5 million, or 6%, lower than 2004. *Petrojarl Foinaven* had revenues of $89.2 million in 2005 compared to $96.6 million in 2004, a decrease of 8%. This reduction relates primarily to a natural decline in the production level of the field. *Petrojarl I* had revenues of $53.4 million in 2005 compared to $61.3 million in 2004, a decrease of 13%, primarily due to natural field production decline. Revenues from *Ramform Banff* were $46.5 million in 2005 compared to $51.5 million in 2004, a decrease of 10%. Revenues from *Petrojarl Varg* increased $2.8 million, or 3% to $89.9 million in 2005 compared to $87.1 million in 2004. In 2004 the production from *Petrojarl Varg* was affected by a shut down that lasted 15 days in October related to a labor conflict on the Norwegian Continental Shelf. The production from the Varg vessel was also reduced, due to damage to the main production riser, from November 5, 2004, to March 9, 2005.

Operating costs (cost of sales, research and development, and selling, general and administration) totaled $781.2 million in 2005 compared to $708.0 million in 2004, an increase of $73.2 million. Marine Geophysical increased operating costs by $38.7 million, mainly as a result of increased activity and price inflation partly offset by increased investments in multi-client library. Onshore reported a $32.5 million increase of operating costs, primarily related to mobilization costs incurred on new projects in Nigeria and Libya. Production operating cost increased $18.8 million, primarily due to replacement of mooring lines and anchor chains on *Petrojarl Foinaven*. Pertra was included for two months in 2005 compared to a full year in 2004. The sale of Pertra caused an approximately $20 million decline in operating costs (after taking into account elimination of inter segment sales and costs).

Depreciation and amortization for 2005 was $280.2 million compared to $327.0 million in 2004, a decrease of $46.8 million, or 14%, primarily due to the sale of Pertra which caused a reduction of depreciation and amortization by $40.9 million. Ordinary gross depreciation expense decreased by $37.0 million, or 23%, to $120.7 million in 2005, mainly caused by the sale of Pertra. Gross depreciation in Marine Geophysical increased by $5.0 million, with a decrease in Onshore of $2.2 million, while depreciation in Production was in line with 2004. Depreciation capitalized as part of the cost of multi-client library increased by $1.4 million to $5.4 million in 2005.

Amortization of multi-client data library increased by $8.4 million, or 5%, to $164.9 million in 2005. Amortization as a percentage of multi-client revenues was 57% in 2005 compared to 66% in 2004. Amortization for 2005 included an additional charge for minimum amortization of $40.1 million and $26.1 million of non-sales related amortization (impairment) to reflect reduced fair value of future sales on certain individual surveys. Amortization for 2004 included an additional charge for minimum amortization of $7.8 million and $23.5 million for non-sales related amortization (impairment).

Operating profit was $581.8 million in 2005 compared to an operating profit of $88.7 million in 2004. Operating profit in 2005 includes a gain from the sale of Pertra of $158.7 million and a reversal of previous impairments on seismic vessels and FPSOs of $310.0 million as a result of a substantial increase of the estimated fair value of certain of these assets following a strong improvement in market conditions and profitability.

Interest expense was $96.8 million in 2005 compared to $111.2 million in 2004. Other financial items amounted to a loss of $2.7 million in 2005 compared to a loss of $11.2 million in 2004.

The 2005 financial statements include a charge of $107.3 million relating to debt premiums and refinancing costs (including $0.4 million in write-off of deferred issue costs) when the Company in 2005 repaid its $250 million 8% Senior Notes due 2006 and $741.3 million of its $746 million 10% Senior Notes due 2010.

Net income tax expense (benefit) was a benefit of $3.4 million in 2005 compared to an expense of $28.6 million in 2004. The net tax benefit in 2005 consist of a current tax expense of $19.7 million that primarily relates to withholding taxes and other taxes payable in regions where we have no carry-forward losses, and a deferred tax benefit of $23.1 million. The deferred tax benefit consist of a benefit of $20.0 million in expected future utilization of deferred tax assets in Norway, a benefit of $4.3 million which is a reduction in Pertra's deferred tax liability in January and February, and an expense of $1.2 million related to other jurisdictions.

Net income for 2005 was $379.1 million compared to a net loss of $53.9 million in 2004.

CASH FLOW, BALANCE SHEET AND FINANCING

Net cash provided by operating activities totaled $279.1 million in 2005 compared to $281.6 million in 2004.

Cash and cash equivalents (excluding restricted cash) totaled $121.5 million at December 31, 2005 compared to $132.9 million at December 31, 2004. Restricted cash totaled $24.5 million at December 31, 2005 compared to $35.5 million at December 31, 2004.

During 2005 we repaid all of our $250 million 8% Senior Notes, due 2006, with cash proceeds from the sale of Pertra and other available cash. In December 2005 we refinanced $741 million of our $746 million 10% Senior Notes, due 2010, with a new term loan of $850 million. At the same time, the previous credit facility of $110 million was replaced by a new credit facility of $150 million. We paid a total of $105.4 million of debt premiums over par value in connection with the repayment of the 8% and 10% Senior Notes and $1.5 million in refinancing costs. The refinancing is expected to significantly reduce future interest costs.

The new term loan matures in December 2012 and has an interest rate of LIBOR plus 250 basis points. The rate will be reduced to LIBOR plus 225 basis points if our leverage ratio (as defined in the loan agreement) is less than 2.25 to 1.

Our new credit facility matures in December 2010. At December 31, 2005, $14.6 million of letters of credits were issued under the facility.

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

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

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

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

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

SALE OF PERTRA TO TALISMAN

On March 1, 2005, we sold our wholly owned subsidiary Pertra AS to Talisman for an initial sales price of approximately $155 millon, which resulted in a gain of $150.6 million, including the $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg*.

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

PROPOSED SEPARATION OF THE GEOPHYSICAL AND PRODUCTION BUSINESSES

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

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

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

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

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

We will provide more detailed information related to the separation and demerger in a shareholder information statement prior to the extraordinary general meeting of our shareholders.

In connection with the demerger, we have entered into other agreements, subject to final documentation, either as part of the proposed demerger plan or otherwise, to facilitate the demerger. For our UK leases on three of our Ramform seismic vessels and the production equipment for the *Ramform Banff*, we have entered into agreements, subject to final documentation, with the lessors providing for certain options with respect to the termination of the leases at reduced termination fees, subject to completion of the demerger.

FINANCIAL MARKET RISK

We are exposed to certain market risks, including adverse changes in interest rates and foreign currency exchange rates, as discussed below.

Interest rate risk

We enter into financial instruments, such as interest rate swaps, to manage the impact of possible changes in interest rates.

As of December 31, 2005, we had $851 million of interest bearing debt with floating interest rate based on USD three months LIBOR rate plus a margin. For every one percentage point increase in the LIBOR rate our interest expense will increase by approximately $8.5 million. For every one percentage point increase in the LIBOR, the annual amount of interest we would receive on interest rate swaps in place as of December 31, 2005 would increase by $4.2 million. Based on such amount of indebtedness and interest rate swaps, a one-percentage point increase in LIBOR would result in a net increase in our annual interest costs of approximately $4.3 million.

We have entered into certain capital leases in the United Kingdom. The leases are legally defeased because we have made payments to independent third-party banks in consideration for which these banks have assumed liability to the lessors equal to basic rentals and termination sum obligations. The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9%. If actual interest rates are greater than the assumed interest rates, we receive rental rebates. If, on the other hand, actual interest rates are less than the assumed interest rates, we are required to pay rentals in excess of the defeased rental payments. For every one percentage point that LIBOR exceeds these assumed interest rates, we are entitled to receive approximately 10.4 million British pounds (approximately $18.0 million) in rental rebates. On the other hand, for every one percentage point that LIBOR is less than these assumed interest rates, we are required to pay an additional approximately 10.3 million British pounds (approximately $17.9 million) in defeased rental payments. During 2005, 2004 and 2003, actual interest rates were below the assumed interest rates, and we made additional required rental payments of $7.2 million for each of the years 2005 and 2004, and $6.4 million in 2003.

Currency Exchange Risk

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

Our cash flows from operations are primarily denominated in USD, GBP and NOK. We predominantly sell our products and services in USD while some portions of our operating expenses are incurred in GBP and NOK. We therefore typically have higher expenses than revenues denominated in GBP and NOK.

In 2005 we adopted a foreign currency hedging program by buying NOK and GBP on forward contracts. As of December 31, 2005 we had open forward contracts to buy GBP and NOK amounting to $194 million with a negative fair value of $7.2 million. At end 2004, we did not have any open forward exchange contracts.

If GBP had appreciated by a further 10% against the USD at year-end, the fair value of the forward contracts on buying GBP would have increased by $5.7 million. A similar 10% appreciation of NOK against USD would have increased the fair value of the forward contracts on buying NOK by $11.9 million.

Substantially all of our debt is denominated in USD.

Credit risk

Our 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 we had a cash balance of $121.5 million and an unused $135.4 million five-year secured revolving credit facility (maturing December 2010). We also have an additional overdraft facility of NOK 50 million.

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

Commodity Risk

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

INVESTMENTS

During 2005, we made a total cash investment of $55.7 million in multi-client data library compared to $42.2 million in 2004, an increase of $13.5 million, or 32%.

Capital expenditures totaled $90.5 million in 2005 compared to $148.4 million in 2004, a decrease of $57.9 million. The decrease mainly relates to Pertra which had a substantial investment program in 2004. Capital expenditures in Marine Geophysical increased $15.3 million to $72.2 million in 2005. This increase relates primarily to an acceleration of the Company's program to replace old streamers and increase the total streamer capacity, as well as other investments to improve the efficiency of seismic vessels and increase data processing capacity.

SHARES, SHARE CAPITAL AND DIVIDEND

Our Annual General Meeting on June 8, 2005, approved the split of our shares in the ratio of three-for-one. Following the split, and as of December 31, 2005, we had 60 000 000 shares issued and outstanding, all of which are of the same class and with equal voting and dividend rights. Each share has a par value of NOK 10.

Our shares are listed on the Oslo Stock Exchange. Our American Depositary Shares ("ADSs") are listed on the New York Stock Exchange.

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

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

HEALTH, SAFETY, ENVIRONMENT AND QUALITY ("HSE&Q")

HSE&Q management and reporting is a key element in our 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. We have made considerable investments to further develop our HSE&Q systems and competence. We place considerable emphasis on prevention and reduction of negative environmental impact of our operations worldwide. We apply a structured approach to ensure that our responsibilities are well managed, and we strive for continuous improvement.

2005 was a good year with strong HSE&Q performance. Our safety and environment results compare favorably with the norm in the industries in which we operate. Our HSE&Q results effectively support our efforts to develop and maintain our position as a market leader in both geophysical and harsh environment floating production services.

HSE&Q achievements in 2005 include:

- Improved the overall score on Lost Time Incident Frequency and Total Recordable Incident Frequency
- No lost time incident in PGS Production, second year in row
- Developed and implemented annual and individual HSE improvement plans for each of the Business Unit Presidents
- Achieved ISO 9001 certification for three of our Data Processing Centers
- Developed a new Corporate Risk Management Framework
- Implemented new system for Incident Management

We experienced one fatality with one of our sub-contractors in Libya, and three lost time incidents in 2005.

Overall, lost time incident frequency (LTIF) was 0.29 per million man hours in 2005, compared to 0.40 for 2004. The total recordable case frequency (TRCF) was 2.19 per million man hours in 2005 compared to 2.33 in 2004. Sick leave in our Norwegian operations was 2.5% in 2005 compared to 4.5% in 2004.

ORGANIZATION

Employees by business area are specified as follows:

	December 31, 2005	2004	2003
Marine Geophysical	1 192	1 115	1 143
Onshore [(a)]	3 237	1 011	1 479
Production	512	501	515
Pertra (sold March 2005)	0	16	5
Global services/Reservoir/Corporate	189	256	235
Total	5 130	2 899	3 377

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

The nature of our operations requires a high degree of technological expertise among our personnel. Traditionally a high proportion of our employees have been male. We strive for balance and equality with respect to sex, age and cultural background, and consider this as a main element of our core values. At December 31, 2005, 9% of our employees were female and 91% male, while the allocation for our Norwegian employees was 21% female and 79% 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% of this group is employed in 80% or less of a full time position. In management positions at PGS' headquarters at Lysaker, 26% are female and 74% are male. Our Board of Directors has 6 male and 1 female directors.

Our head office is at Lysaker, Norway. We also have offices in other cities in Norway, and in Angola, Azerbaijan, Australia, Bangladesh, Bolivia, Brazil, Canada, China, Ecuador, Egypt, England, France, Indonesia, Kazakhstan, Libya, Malaysia, Mexico, Nigeria, Russia, Scotland, Singapore, United Arab Emirates, U.S. and Venezuela.

BOARD OF DIRECTORS AND CORPORATE GOVERNANCE

In 2005 our Board of Directors consisted of Jens Ulltveit-Moe (Chairperson), Keith Henry (Vice chairperson), Francis Gugen, Harald Norvik, Rolf Erik Rolfsen, Clare Spottiswoode and Anthony Tripodo, all elected as permanent directors for a one year period at the Annual General Meeting held on June 8, 2005.

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

We also have a Nomination Committee, elected by our shareholders, consisting of Roger O'Neil (Chairperson), Hanne Harlem and C. Maury Devine.

In 2005 our Board of Directors had 13 meetings.

We are committed to maintain high standards of corporate governance. We believe that effective corporate governance is essential to the success of PGS 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 our governance model is built on Norwegian corporate law. We also adhere to requirements applicable to foreign registrants in the U.S., where our ADSs are publicly traded, including the New York Stock Exchange listing standards. We otherwise implement corporate governance guidelines beneficial to our business.

Our corporate governance principles are adopted by our Board of Directors. Our Board conducts a periodic review of these principles. Key aspects of our corporate governance structure are described in more detail in the separate corporate governance report in the 2005 annual report. Our articles of association, in addition to full versions of the rules of procedures for our Board of Directors, the Audit Committee charter, the Remuneration Committee charter, the Nomination Committee charter and our code of conduct are available on our website (www.pgs.com).

OUTLOOK

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

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

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

Marine Geophysical

- Marine 3D industry seismic fleet at full capacity utilization with PGS streamer contract margins expected to improve by more than 10 percentage points compared to full year 2005
- Multi-client late sales expected to be lower than 2005 as a result of low level of investments over recent years
- Cash investments in multi-client library expected to double from an investment of $46 million in 2005, with continued high pre-funding levels

Onshore

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

Production

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

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

SETTLEMENT OF THE PARENT COMPANY'S PROFIT FOR 2005

Our parent company, Petroleum Geo-Services ASA, reported a net income of NOK 4 039 290 000 for 2005, which is allocated to other equity. Free equity is NOK 4 028 292 000.

March 27, 2006

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

Petroleum Geo-Services

CONSOLIDATED STATEMENTS OF OPERATIONS

		Years ended December 31,		
(In thousands of dollars)	*Note*	2005	2004	2003
Revenues	*4*	$ 1 193 985	$ 1 135 461	$ 1 120 658
Cost of sales		703 099	639 251	584 717
Depreciation and amortization	*4*	280 173	326 996	305 419
Research and development costs		9 918	3 419	2 622
Selling, general and administrative costs		68 154	65 314	54 251
Impairment (reversal) of long-lived assets	*4, 6*	(305 417)	-	740 876
Net gain on sale of subsidiaries	*5*	(157 384)	-	-
Other operating (income) expense, net	*4, 6*	13 643	11 760	78 085
Total operating expenses		612 186	1 046 740	1 765 970
Operating profit (loss)	*4*	581 799	88 721	(645 312)
Income from associated companies	*7*	276	5 277	897
Interest expense	*8*	(96 799)	(111 233)	(115 459)
Debt redemption and refinancing costs	*26*	(107 315)	-	(13 152)
Other financial items, net	*9*	(2 733)	(11 182)	(14 029)
Income (loss) before income taxes		375 228	(28 417)	(787 055)
Income tax expense (benefit)	*10*	(3 373)	28 558	26 436
Income (loss) from continuing operations		378 601	(56 975)	(813 491)
Income (loss) from discontinued operations, net of tax	*3*	500	3 048	(5 587)
Net income (loss)		$ 379 101	$ (53 927)	$ (819 078)
Hereof minority interest		$ 4 065	$ 350	$ 125
Hereof majority interest	*11*	$ 375 036	$ (54 277)	$ (819 203)

March 27, 2006

Jens Ulltveit-Moe
Chairperson

Clare Spottiswoode

Harald Norvik

Anthony Tripodo

Keith Henry
Vice chairperson

Rolf Erik Rolfsen

Francis Gugen

Svein Rennemo
Chief Executive Officer

Petroleum Geo-Services

CONSOLIDATED BALANCE SHEETS

(In thousands of dollars)	Note	December 31, 2005	2004
ASSETS			
Long-term assets:			
Multi-client library, net	15	$ 137 000	$ 240 596
Other long-lived intangible assets	13	1 982	2 075
Deferred tax assets	10	20 000	-
Property and equipment, net	14	1 314 879	1 042 279
Oil and natural gas assets, net	16	98	63 956
Restricted cash	21	10 014	10 014
Investments in associated companies	4, 7	5 935	5 720
Other financial assets	17	37 133	40 105
Total long-term assets		1 527 041	1 404 745
Current assets:			
Accounts receivable, net	18	281 406	201 844
Other current assets	19	67 737	60 506
Shares available for sale and investments in securities	20	13 222	9 689
Restricted cash	21	14 494	25 477
Cash and cash equivalents		121 464	132 942
Total current assets		498 323	430 458
Total assets	4	$ 2 025 364	$ 1 835 203
LIABILITIES AND SHAREHOLDERS' EQUITY			
Shareholders' equity:			
Paid in capital:			
Common stock; 60 000 000 shares authorized, issued and outstanding, par value NOK 10, at December 31, 2005 and 20 000 000 shares authorized, issued and outstanding, par value NOK 30, at December 31, 2004		$ 85 714	$ 85 714
Additional paid in capital		287 576	287 576
Total paid in capital		373 290	373 290
Other equity		298 601	(70 436)
Minority interest		1 049	1 226
Total shareholders' equity		672 940	304 080
Debt:			
Accruals for long-term liabilities:			
Deferred tax liabilities	10	497	28 445
Other long-term liabilities	24	105 702	133 342
Total accruals for long-term liabilities		106 199	161 787
Other long-term debt:			
Long-term capital lease obligations	12	13 205	33 156
Long-term debt	26	922 134	1 085 190
Total other long-term debt		935 339	1 118 346
Current liabilities:			
Short-term debt and current portion of long-term debt	25, 26	24 406	19 790
Current portion of capital lease obligations	12	20 495	25 583
Accounts payable		74 285	81 910
Accrued expenses	27	164 327	112 673
Income taxes payable	10	26 318	8 259
Deferred tax liabilities	10	1 055	2 775
Total current liabilities		310 886	250 990
Total liabilities and shareholders' equity		$ 2 025 364	$ 1 835 203

Petroleum Geo-Services

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of dollars)	Years ended December 31, 2005	2004	2003
Cash flows from operating activities:			
Net income (loss)	$ 375 036	$ (54 277)	$ (819 203)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization charged to expense	280 173	326 996	305 419
Non-cash impairments and loss (gain) on sale of subsidiaries	(462 801)	-	745 697
Non-cash write-off of deferred debt costs and issue discounts	363	-	13 152
Cash effects related to discontinued operations	-	-	3 342
Non-cash other operating (income) expense, net	13 643	-	-
Premium debt redemption and cost of refinancing expensed	106 952	-	-
Provision (benefit) for deferred income taxes	(23 116)	26 970	(4 639)
Changes in current assets, current liabilities and other	(14 256)	(37 881)	(9 988)
Loss on sale of assets	1 720	4 128	6 193
Net (increase) decrease in restricted cash	1 342	15 646	(19 904)
Net cash provided by operating activities	279 056	281 582	220 069
Cash flows (used in) provided by investing activities:			
Investment in multi-client library	(55 667)	(42 159)	(91 500)
Capital expenditures	(90 490)	(148 372)	(57 710)
Capital expenditures on discontinued operations	-	-	(118)
Proceeds from sale of subsidiares, net	155 356	2 035	50 115
Other items, net	1 300	4 031	3 835
Net cash (used in) provided by investing activities	10 499	(184 465)	(95 378)
Cash flows (used in) provided by financing activities:			
Proceeds from issuance of long-term debt	850 000	-	-
Redemption of preferred stock	-	-	(64 105)
Repayment of long-term debt	(1 009 152)	(24 167)	(11 241)
Principal payments under capital leases	(25 700)	(21 121)	(17 539)
Net increase (decrease) in bank facility and short-term debt	712	1 962	(48)
Distribution to creditors under the restructuring agreement	-	(22 660)	(17 932)
Premium on debt redemption, deferred loan cost and reorganization fees	(116 813)	(3 488)	-
Net cash used in financing activities	(300 953)	(69 474)	(110 865)
Effect of exchange rate changes on cash	(80)	74	14
Net increase (decrease) in cash and cash equivalents	(11 478)	27 717	13 840
Cash and cash equivalents at beginning of year	132 942	105 225	91 385
Cash and cash equivalents at end of year	$ 121 464	$ 132 942	$ 105 225

Petroleum Geo-Services

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Common Stock			Other equity					
(In thousands of dollars, except for share data)	Number	Par value	Additional paid-in capital	Net foreign currency translation adjustments	Net unrealized gain (loss) reserves	Other equity	Total other equity	Minority interest	Share-holders' equity
Balance at December 31, 2003	20 000 000	$ 85 714	$ 287 576	$(4 571)	$ -	$ (15 547)	$ (20 118)	$ 1 527	$ 354 699
Net income (loss)	-	-	-	-	-	(54 277)	(54 277)	350	(53 927)
Dividens to minority interest	-	-	-	-	-	-	-	(264)	(264)
Revaluations of shares available for sale	-	-	-	-	5 889	-	5 889	-	5 889
Translation adjustments and other	-	-	-	(1 666)	-	(264)	(1 930)	(387)	(2 317)
Balance at December 31, 2004	20 000 000	$ 85 714	$ 287 576	$(6 237)	$ 5 889	$ (70 088)	$ (70 436)	$ 1 226	$ 304 080
Share split June 8, 2005	40 000 000								
Net income	-	-	-	-	-	375 036	375 036	4 065	379 101
Dividends to minority interest	-	-	-	-	-	-	-	(204)	(204)
Revaluations of shares available for sale and investments in securities	-	-	-	-	(1 837)	-	(1 837)	-	(1 837)
Revaluations interest rate swaps	-	-	-	-	(1 628)	-	(1 628)	-	(1 628)
Translation adjustments and other	-	-	-	(2 534)	-	-	(2 534)	(4 038)	(6 572)
Balance at December 31, 2005	60 000 000	$ 85 714	$ 287 576	$(8 771)	$ 2 424	$ 304 948	$ 298 601	$ 1 049	$ 672 940

Petroleum Geo-Services ASA has one class of shares, and as of December 31, 2005, common stock consisted of a total of 60 000 000 shares of par value NOK 10 each fully paid in.

The shareholders voting rights are equal to ownership percentage. A listing of the Company's largest shareholders is provided in Note 22.

Petroleum Geo-Services

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. PGS provides a broad range of geophysical and reservoir services, including seismic data acquisition, processing and interpretation and field evaluation. In the North Sea, the Company owns and operates four harsh environment floating production, storage and offloading vessels ("FPSOs"). The Company's headquarters are at Lysaker, Norway. See further discussion of the Company's services in Note 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 oil and natural gas subsidiary Pertra AS in March 2005 and entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS in August 2005. The financial results of operations and cash flows for these subsidiaries are included in the consolidated statements of operations and consolidated cash flows for the periods up to sales date. The operations are not presented as discontinued due to continuing involvement through the lease of *Petrojarl Varg*.

The Company sold its software company PGS Tigress (UK) Ltd. in December 2003 and its Atlantis subsidiary in February 2003. The financial position and results of operations and cash flows for these subsidiaries have been presented as discontinued operations as of December 31, 2003 and for the year ended December 31, 2003. Discontinued operations and related cash flows for the years ended December 31, 2005 and 2004 includes additional proceeds that were contingent on certain events related to discontinued operations sold in 2002 (Production Services). See Note 3 for additional information of these disposals.

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, "Financial Reporting by Entities in Reorganization under the Bankruptcy Code," 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 $740.9 million of impairments under N GAAP in 2003.

In 2005 the Company decided to convert its 4C crew into a streamer operation, resulting in an impairment of $4.6 million. The Company also recorded reversals of previous recognized impairments for $212.0 million relating to FPSOs and $98.0 million relating to seismic vessels (see Note 14).

During 1996 to 1998 the Company entered into capital leases relating to certain of the Company's Ramform seismic vessels and FPSOs for terms ranging from 13-25 years. The Company has indemnified the lessors for the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities and for variations in actual interest rates from those assumed in the leases. There are no limits on either of these indemnities. The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. During 2005 the UK Inland Revenue has accepted such tax depreciation for all the Company's UK leases, apart from the *Petrojarl Foinaven* lease where the UK Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available. As a consequence, the Company, as of December 31, 2005, recorded an accrual of 13.0 million British pounds (approximately $22.5 million) for this possible liability. See Note 12 for additional information on this possible liability and on our UK leases generally.

MATERIAL WEAKNESSES

The Company has concluded that by year end December 31, 2005, material weaknesses relating to its internal controls over financial reporting, that previously were identified, had been remediated. However, two significant control deficiencies remained as of December 31, 2005 regarding the sufficiency of our supervisory review procedures related to income tax provision and, in addition, that not all significant accounting issues were documented and concluded upon timely with sufficient detail and technical reference. Our assessment also identified certain other control deficiencies. We believe that these deficiencies do not represent a material weakness condition, either individually or in aggregate.

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. The transition rules apply to the Company and the Company plans to defer IFRS reporting until January 1, 2007.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

CONSOLIDATION AND EQUITY INVESTMENTS

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

Investments in associated companies in which the Company has an ownership interest equal to or greater than 20% but equal to or less than 50%, and where the Company has the ability to exercise significant influence are accounted for using the equity method. The equity method implies that the Company's share of net income in the associated company is included in a separate line in the consolidated statements of operations, while the Company's share of the associated company's equity, adjusted for any excess values of goodwill, is classified as a long-term asset in the consolidated balance sheets.

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

Shares available for sale and investments in securities with an available market value are carried at fair value at each balance sheet date, with unrealized holding gains and losses reported in other equity until realized. Gains and losses are recognized in the consolidated statements 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 consolidated balance sheets. For further details about subsidiaries that we have sold or operations that we have discontinued, see Note 3.

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.

CASH AND CASH EQUIVALENTS

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

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

FOREIGN CURRENCY TRANSLATION

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

The financial statements of non-US subsidiaries using their respective 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, 2005 and 2004 was NOK 6.76 and NOK 6.13, 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 mainly for land seismic equipment and UK leases for vessels (see "UK Leases" below). Capital leases are lease arrangements in which the substantial financial risk and control, but not ownership, of the assets are transferred from the lessor to the Company.

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

UK LEASES

The Company has entered into vessel lease arrangements in the United Kingdom ("UK leases") relating to five of its Ramform-design seismic vessels, its FPSO vessel *Petrojarl Foinaven* and the topside production equipment for its FPSO vessel *Ramform Banff* (see Note 12). Generally, 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. The Company indemnified the Lessors for the tax consequence resulting from changes in tax laws or interpretation of such laws or adverse rulings by authorities and for variations in actual interest rates from those assumed in the lease.

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") and termination sum obligations under the agreements. The Company has no rights to the amounts paid to Payment Banks. Due to the assumption of the charter payment obligations by the Payment Banks, the Lessors legally released the Company as the primary obligor under the charters. Accordingly, the Company accounted for the release as a derecognition of the capital lease obligations with respect to these UK leases.

At the date that the Company executed any UK lease, the Company treated the excess of the capitalized asset value over the amount required to legally defease the charter obligations as a deferred gain. The deferred gain related to indemnification for tax contingencies and for changes in future interest rates. In issued at and prior to December 31, 2003 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 year ended December 31, 2003 was restated to reflect this accounting.

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

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.

PENSION OBLIGATIONS

Pension obligations are calculated as the discounted value of future pension benefits deemed to have accrued at year-end, based on employees earning pension rights steadily throughout their working period. Funds belonging to the pension scheme are assessed at their fair value and recorded as other financial assets, while net pension liabilities on underfunded plans are recorded as other long-term liabilities in the consolidated balance sheets. Pension obligations and pension scheme funds are calculated on the basis of financial and actuarial assumptions as described in Note 29.

The effect of changes in estimates and the difference between actual and anticipated returns are spread forward over the average remaining service lives of employees when the cumulated effect exceeds 10% of whichever is higher of the pension scheme funds or the pension obligations. Changes in the pension obligations due to changes in pension plans are either;

- recognized over the estimated average remaining service period if the change in plan has retrospective effect and is conditional upon future employment,
- recognized immediately if the change in plan has retrospective effect but is not conditional upon future employment.

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 data surveys to be licensed to customers on a nonexclusive basis. Costs directly incurred in acquiring, processing and otherwise completing seismic surveys are capitalized into the multi-client library, including the applicable portion of interest costs.

The Company records its investment in the 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).

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.

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. Management updates, at least annually, the total expected revenue for each survey or group of surveys of the multi-client library. Because of the inherent difficulty in estimating future sales and market developments, it is possible that the amortization rates could deviate significantly from year to year. To the extent that such revenue estimates, or the assumptions used to make those estimates, prove to be higher than actual revenue, the Company's future operations will reflect lower profitability due to increased amortization rates applied to the multi-client library in later years, and the multi-client library may also become subject to minimum amortization and/or impairment. Effective 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 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 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 permitted 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 permitted 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 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 project completion	Marine surveys	Land surveys
2003	100%	100%
2002	80%	80%
2001	60%	60%
2000	40%	40%
1999	20%	20%
1998	20%	0%
1997	10%	
1996	0%	

New surveys		
Calendar year after project completion	5-year profile	3-year profile
Year 0 (a)	100%	100%
Year 1	80%	66%
Year 2	60%	33%
Year 3	40%	0%
Year 4	20%	
Year 5	0%	

a) Represents the year in which the survey is classified as completed.

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

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 and capital leases, 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 property and equipment, as of December 31, 2005, 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.

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

OTHER LONG-LIVED INTANGIBLE ASSETS

Other long-lived intangible assets generally relate to direct costs of software product development, patents, royalties and licenses, and 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 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 financial assets 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 overfunded plans.

IMPAIRMENT OF LONG-LIVED ASSETS, INCLUDING MULTI-CLIENT LIBRARY

Long-lived assets, which consist primarily of multi-client library, property, plant and equipment and oil and natural 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. 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.

The estimation of future cash flows and fair value is highly subjective and inherently imprecise. Estimates can change materially from period to period based on many factors including historical and recent revenue trends, oil and gas prospects, in particular regions, general economic conditions affecting the Company's customer base, expected changes in technology and other factors that are deemed relevant.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized, in which case the carrying amount of the asset is increased to its recoverable amount, but not exceeding the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in the consolidated statements of operations. After such a reversal the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount , less any residual value, on a systematic basis over its remaining useful life.

STEAMING AND MOBILIZATION COSTS

Costs incurred while relocating or "steaming" a vessel or crew from one location to another are expensed as incurred. Onsite project cots 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.

DERIVATIVE FINANCIAL INSTRUMENTS

The Company uses derivative financial instruments to reduce risk exposure related to fluctuations in foreign currency rates and interest rates. Derivative instruments are recognized in the consolidated balance sheets at their fair values while realized and unrealized gains and losses attributable to derivative instruments that do not qualify for hedge accounting are recognized as other financial items, net, in the consolidated statements of operations as they arise. Unrealized amounts related to the effective portion of qualifying hedging instruments are recorded as a reduction of other equity (see Note 28).

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

The Company applies hedge accounting for its interest rate hedging activities. At December 31, 2005, for a portion of its floating rate debt, the Company has entered into interest rate swaps to effectively change the floating interest rates to fixed interest rates. The Company does not apply hedge accounting for its currency hedging activities (see Note 28).

REVENUE RECOGNITION

The Company recognizes revenue when persuasive evidence of a sale arrangement exists, delivery has occurred or services have been rendered, the sales price is fixed or determinable and collection is reasonably assured. The Company defers the unearned component of payments received from customers for which the revenue recognition requirements have not been met. 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. 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.

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

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

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

(b) Proprietary Sales/Contract Sales

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

(c) Other Geophysical Services.

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

2. Production Services

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

3. Pertra

Revenue from production and sale of oil produced under production licenses is recognized as produced barrels are lifted and ownership passes to 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 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 indefinite.

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 recorded, the Company capitalizes the cost by increasing the carrying amount of the related properties, plant and equipment. Over time, the liability is increased for the change in its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Also, revisions to a previously recorded ARO may result from changes in the assumptions used to estimate the 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 the sub-sea production facility associated with *Ramform Banff* FPSO operating in the North Sea. These obligations generally relate to restoration of the environment surrounding the facility and removal and disposal of all the production equipment. The asset retirement obligations will be covered in part by contractual payments from FPSO contract counterparties. The receivable has been included in the consolidated balance sheets under other financial assets.

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.

OIL AND NATURAL GAS ASSETS

This policy applies only to Pertra, which was sold March 1, 2005 (see Note 3).

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 not to have commercial quantities of reserves, the drilling and equipment costs for the well are expensed as depreciation expense at that time. Such expenses aggregated $11.4 million for the year ended December 31, 2004, while there were no such costs for the years ended December 31, 2005 and 2003. All development drilling and equipment costs are capitalized. Capitalized costs of proved properties are amortized on a property-by-property basis using the unit-of-production method whereby the ratio of annual production to beginning of period proved oil and natural gas reserves is applied to the remaining net book value of such properties. Oil and natural gas reserve quantities represent estimates only, and there are numerous uncertainties inherent in the estimation process. Actual future production may be materially different from amounts estimated, and such differences could materially affect future amortization of proved properties. Geological and geophysical costs are expensed as incurred and presented as cost of sales and aggregated $1.4 million, $4.9 million and $4.3 million for the years ended December 31, 2005, 2004 and 2003, respectively.

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.

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.

NOTE 3 – ACQUISITIONS AND DISPOSITIONS

In 2002, the Company sold its Production Services (formerly Atlantic Power Group) subsidiary to Petrofac Limited. The Company is eligible to receive an additional consideration of $2.5 million upon the occurrence of certain contingent events through 2010.

In February 2003, the Company sold its Atlantis oil and gas activities to Sinochem and received proceeds and reimbursements aggregating $59.2 million. The Company was entitled to receive up to $25.0 million in additional, contingent proceeds, which agreement was amended in June 2005. In accordance with the amended agreement, the Company may receive a maximum of $10.0 million in contingent proceeds upon the occurrence of certain contingent events, which currently has not been recognized.

In December 2003, the Company sold its wholly owned software company PGS Tigress (UK) Ltd. for a deferred compensation of approximately $1.8 million, payable 2004 through 2007, for which payments were received in December 2005 and 2004. The Company may also receive additional contingent proceeds based on performance of the company through 2006. As of December 31, 2005, the Company had not received any such contingent proceeds. The Company recognized no net gain or loss on the sale of Tigress.

In March 2005, the Company sold its wholly owned oil and natural gas subsidiary Pertra AS to Talisman Energy (UK) Ltd. for an initial sales price of approximately $155 million. Pertra AS was renamed Talisman Production Norge AS. The Company recognized a $150.6 million gain from the sale, including the $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg*, recognized as net gain on sale of subsidiaries. As part of the transaction, the Company is entitled to receive additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006, we received $8.1 million, representing the 2005 portion of the contingent consideration. The Company accrued this amount in December 2005 and recognized the amount as additional gain on the 2005 sale (see Note 5). The Company also granted an option enabling Talisman to change the termination clause with respect to PL038. The option expired on February 1, 2006 without being exercised. Assets relating to Pertra as of December 31, 2004 are shown below, while the results of operations and capital expenditures for the periods presented up to March 1, 2005 are presented as a separate segment in our consolidated statements of operations (see Note 4). The operations of Pertra are not presented as discontinued operations due to continuing involvement through the charter of *Petrojarl Varg*.

In August 2005, the Company entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS to Reservoir Consultants Holding AS ("RCH"), which is controlled by a group of former PGS employees. RCH has the option to sell the shares back to the Company for an amount equal to the consideration (approximately $0.5 million), which option expires 12 months from completion date (August 31, 2005). The Company has recorded an estimated loss of $1.3 million for this transaction, recognized in net gain on sale of subsidiaries (see Note 5). In addition the Company recorded assets and liabilities of business transferred under the contractual arrangement aggregating $3.5 million gross. Such assets and liabilities are recognized in other current assets and accrued expenses (see Notes 19 and 27).

The results of operations, net assets and cash flows for Tigress have been presented as discontinued operations, and are summarized as follows for the years presented:

(In thousands of dollars)	Year ended December 31, 2003
Revenues	1 244
Operating expenses before depreciation, amortization, impairment, net gain on sale of subsidiaries and other operating (income) and expense, net	(2 697)
Depreciation and amortization	(707)
Other operating (income) and expense, net	(512)
Total operating expenses	(3 916)
Operating loss	(2 672)
Interest expense and other financial items, net	(1 213)
Income (loss) before income taxes	(3 885)
Capital expenditures on discontinued operations	118

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

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Income (loss) before income taxes	---	---	(3 885)
Loss on disposal	---	---	(4 821)
Additional proceeds	500	3 048	3 500
Income tax benefit (expense)	---	---	(381)
Income (loss) from discontinued operations, net of tax	500	3 048	(5 587)

Operating expenses relating to discontinued operations include corporate management fees based on actual charges to these entities. For continuing operations, such fees are presented in the segment for Reservoir/Shared Services/Corporate (see Note 4). Allocation of interest expense to discontinued operations is based on actual interest charged to the respective entities.

The operations of Pertra are presented as a separate segment in our consolidated statements of operations (see Note 4). Assets and liabilities relating to Pertra as of December 31, 2004 were as follows:

(In thousands of dollars)	December 31, 2004
Cash and cash equivalents	13 423
Accounts receivable, net	7 406
Other current assets	15 916
Property and equipment, net	937
Oil and natural gas assets, net	63 956
Other long-lived assets	12 001
Total assets	113 639
Accounts payable	1 624
Accrued expenses	6 135
Deferred tax liabilities, current	2 775
Other long-term liabilities	39 914
Deferred tax liabilities, long-term	28 080
Total liabilities	78 528

SUBSEQUENT EVENTS

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

As described above, the Company may receive $10 million in additional contingent proceeds, upon occurrence of certain contingent events, from the sale of Atlantis in 2003. At December 31, 2005, the Company had not accrued for these proceeds. In March 2006, the Company received confirmation of occurrence of certain of these events in 2006 that entitles the Company to receive $6 million, of which $3 million was received in March 2006.

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

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

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

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

If the demerger plan is approved by the requisite two-third vote of the Company's shareholders and the conditions precedent to consummation of the demerger are satisfied, or where applicable waived, the Company currently expects the demerger to be consummated on or about June 30, 2006.

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

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

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

The demerged Production business will be presented as held-for-sale (discontinued operations) in the consolidated financial statements from the time of the demerger. In addition, historical financial information of the Pertra operations will be presented as discontinued operations from the same date, as the continued business relations with Pertra related to *Petrojarl Varg* will be discontinued with the demerger of the Production business.

NOTE 4 – SEGMENT AND GEOGRAPHIC INFORMATION

The Company, after the sale of Pertra AS in March 2005, manages its business in three segments as follows:

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

Pertra AS, a small oil and natural gas company, was sold in March 2005 (see Notes 3 and 5) and was a separate segment. Revenues and expenses, assets and liabilities are included in the consolidated statements through February 2005 and in the comparative numbers for the years presented. The operations of Pertra are not presented as discontinued operations due to continuing involvement through the lease of *Petrojarl Varg*.

The Company manages its Marine Geophysical segment from Lysaker, Norway, its Onshore segment from Houston, Texas, and its Production segment from Trondheim, Norway.

The principal markets for the Production segment are the UK and Norway. The Marine Geophysical and Onshore segments serve a worldwide market. Customers for all segments are primarily composed of major multi-national, independent and national or state-owned oil companies. Corporate overhead has been presented under Reservoir/Shared Services/Corporate. Significant charges, which do not relate to the operations of any segment, such as debt refinancing and restructuring costs, are also presented as Reservoir/Shared Services/Corporate. Information related to discontinued operations during any period presented has been separately aggregated. Inter-segment sales are made at prices that approximate market value. Interest and income tax expense is not included in the measure of segment performance.

REVENUES BY SEGMENT

The table below presents our mix of revenues for the periods presented:

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Marine Geophysical:			
Contract	424 434	298 584	348 117
Multi-client pre-funding	40 006	30 535	49 735
Multi-client late sales	218 781	205 971	148 128
Other	41 703	39 124	38 200
Total Marine Geophysical	724 924	574 214	584 180
Onshore:			
Contract	122 415	110 289	128 073
Multi-client pre-funding	16 148	12 761	16 746
Multi-client late sales	13 976	10 112	9 215
Total Onshore	152 539	133 162	154 034
Production:			
Petrojarl I	53 394	61 303	67 741
Petrojarl Foinaven	89 191	96 595	112 099
Ramform Banff	46 483	51 509	45 694
Petrojarl Varg	89 920	87 133	67 288
Other	1 689	1 662	593
Total Production	280 677	298 202	293 415
Pertra	34 159	186 717	121 641
Reservoir/Shared-Services/Corporate	19 418	20 852	21 200
Elimination inter-segment revenues	(17 732)	(77 686)	(53 812)
Total revenues	**1 193 985**	**1 135 461**	**1 120 658**

ADDITIONAL SEGMENT INFORMATION

Additional segment information for the periods presented is summarized as follows:

(In thousands of dollars)	Marine Geo-physical	Onshore	Production	Pertra	Reservoir/ Shared Services / Corporate	Elimination of inter-segment items	Total
Depreciation and amortization:							
2005	199 655	29 311	39 777	6 863	4 567	---	280 173
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
Operating costs: [(a)]							
2005	403 885	130 677	192 326	31 539	41 400	(18 656)	781 171
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
Segment operating profit:							
2005	121 384	(7 449)	48 574	(4 243)	(26 549)	924	132 641
2004	9 536	(1 739)	84 922	30 654	(21 299)	(1 593)	100 481
2003	52 981	16 847	86 960	36 069	(19 208)	---	173 649
Impairment (reversal) of long-lived assets:							
2005	(93 459)	---	(211 958)	---	---	---	(305 417)
2004	---	---	---	---	---	---	---
2003	359 834	11 822	367 021	---	2 199	---	740 876
Net (gain) on sale of subsidiaries:							
2005	---	---	---	---	(157 384)	---	(157 384)
2004	---	---	---	---	---	---	---
2003	---	---	---	---	---	---	---
Other operating (income) expense, net:							
2005	(8 847)	---	22 490	---	---	---	13 643
2004	(13)	9	---	---	11 764	---	11 760
2003	22 908	304	---	---	54 873	---	78 085
Operating profit (loss):							
2005	223 690	(7 449)	238 042	(4 243)	130 835	924	581 799
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)
Income (loss) from discontinued operations, net of tax: [(b)]							
2005	---	---	500	---	---	---	500
2004	---	---	3 048	---	---	---	3 048
2003	(4 298)	---	3 500	(4 789)	---	---	(5 587)
Investment in associated companies:							
2005	278	---	5 653	---	4	---	5 935
2004	235	---	5 411	---	74	---	5 720
Total assets:							
2005	869 467	102 058	907 275	---	146 564	---	2 025 364
2004	773 485	89 205	721 907	113 639	136 967	---	1 835 203
Additions to long-lived tangible assets: [(c)]							
2005	118 442	21 055	11	103	6 629	(83)	146 157
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
Capital expenditures on discontinued operations: [(b)]							
2005	---	---	---	---	---	---	---
2004	---	---	---	---	---	---	---
2003	118	---	---	---	---	---	118

a) Operating costs include cost of sales, research and development costs, and selling, general and administrative costs.

b) Income (loss) from discontinued operations, net of tax, and capital expenditures on discontinued operations, included in segment data for Marine Geophysical relates to Tigress, Production segment data relates Production Services and Pertra segment data relates to Atlantis.

c) Consists of cash investment 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 located.

Information by geographic region is summarized as follows:

(In thousands of dollars)	Americas	UK	Norway	Asia/Pacific	Africa	Middle East/Other	Elimination of inter-segment items	Total
Revenue, unaffiliated companies:								
2005	311 738	175 440	303 575	199 107	139 317	64 808	---	1 193 985
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
Revenue, includes affiliates:								
2005	312 636	176 053	306 766	199 826	139 679	65 186	(6 161)	1 193 985
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
Total assets:								
2005	294 157	1 068 915	567 754	74 485	10 880	9 173	---	2 025 364
2004	343 941	912 664	471 913	79 462	20 334	6 889	---	1 835 203
Capital expenditures (cash):								
2005	19 183	63 679	5 195	1 579	---	854	---	90 490
2004	7 955	40 812	96 813	1 975	---	817	---	148 372
2003	11 385	7 160	37 246	358	---	1 561	---	57 710

Export sales from Norway to unaffiliated customers did not exceed 10% of gross revenue for the years ended December 31, 2005, 2004 and 2003.

For the years ended December 31, 2005, 2004 and 2003, customers exceeding 10% of the Company's total revenue were as follows (the table shows percentage of revenues accounted for by such customers, and the segments that had sales to the respective customers are marked with X):

	Years ended December 31,						
	2005		2004		2003		
Segments serving customer (each % in each year represents a separate customer):	13%	10%	25%	10%	19%	12%	10%
Marine Geophysical	X	X	X	X	X	X	X
Onshore		X					X
Production	X	X	X	X	X	X	
Pertra	X		X		X		
Reservoir/Shared Services/Corporate	X		X		X		

In certain of the regions were 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 5 – NET GAIN ON SALE OF SUBSIDIARIES

In March 2005, the Company sold its wholly owned subsidiary Pertra AS to Talisman Energy (UK) Ltd. and recognized a gain of $150.6 million, including $2.5 million received to grant an option to make certain amendments to the charter and operating agreement for the *Petrojarl Varg*. As part of the transaction, the Company is entitled to receive additional sales consideration equal to the value, on a post petroleum tax basis, of 50% of the relevant revenues from the Varg field in excess of $240 million for each of the years ended December 31, 2005 and 2006. In January 2006, the Company received $8.1 million, representing the 2005 portion of the contingent consideration, which was accrued for in December 2005, resulting in an aggregate net gain on the sale of Pertra AS of $158.7 million. See Note 3 for additional information relating to the disposal of Pertra AS.

In August 2005, the Company entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS to Reservoir Consultants Holding AS ("RCH"), which is controlled by a group of former employees. RCH has the option to sell the shares back to the Company for an amount equal to the sale consideration, which option expires 12 months from completion date (August 31, 2005). The Company has recorded an estimated loss of $1.3 million for this transaction. See Note 3 for additional information relating to the agreement.

NOTE 6 – IMPAIRMENT (REVERSAL) OF LONG-LIVED ASSETS AND OTHER OPERATING (INCOME) EXPENSE, NET

Impairment (reversal) of long-lived assets consist of the following:

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Multi-client library (Note 15) [(a)]	---	---	241 481
Production assets and equipment (Note 14)	(211 958)	---	367 021
Seismic assets and equipment (Note 14)	(93 459)	---	129 084
Licenses and building leasehold improvements	---	---	3 290
Total	(305 417)	---	740 876

a) The multi-client library impairment for the year ended December 31, 2003, is comprised of $229.7 million in Marine Geophysical and $11.8 million in Onshore.

As of December 31, 2005, the Company calculated and recorded reversal of previous recognized impairments of $212.0 million relating to Production FPSOs and related equipment and $98.0 million relating to seismic vessels and equipment. During 2005 the Company decided to convert its 4C crew into a streamer operation, resulting in an impairment of $4.6 million.

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

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
UK lease, contingent liability (Note 12)	22 490	---	---
Gain on claim re equipment	(8 847)	---	---
Costs relating to completion of 2002 U.S. GAAP accounts and re-audit of 2001	---	7 447	2 559
Debt restructuring/refinancing/"fresh-start"	---	3 471	42 274
Cost of employees termination and reorganization	---	842	20 840
Isle of Man, national insurance liability	---	---	12 412
Total	13 643	11 760	78 085

NOTE 7 – INVESTMENTS IN ASSOCIATED COMPANIES

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

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Corporations and limited partnerships:			
Geo Explorer AS	(2)	1 827	119
Atlantic Explorer (IoM) Ltd.	(5)	(80)	---
Ikdam Production, SA	243	2 030	(5)
Acqua Exploration Ltd.	---	1 500	---
Triumph Petroleum	---	---	787
Calibre Seismic Company	---	---	(4)
General Partnership	40	---	---
Total	276	5 277	897

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

(In thousands of dollars)	Book value December 31, 2004	Share of income 2005	Paid-in capital/ (dividends) 2005	Equity transac-tions [a] 2005	Book value December 31, 2005	Ownership percent as of December 31, 2005
Corporations and limited partnerships:						
Ikdam Production, SA	5 411	243	---	(1)	5 653	40.0%
Geo Explorer AS	182	(2)	---	(15)	165	50.0%
Atlantic Explorer (IoM) Ltd.	32	(5)	---	(3)	24	50.0%
Valiant Intern. Petroleum Ltd.	---	---	68	---	68	24.6%
General partnerships	95	40	(66)	(44)	25	---
Total	5 720	276	2	(63)	5 935	

a) Includes foreign currency translation differences.

NOTE 8 – INTEREST EXPENSE

Interest expense consists of the following:

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Interest expense, gross	(98 677)	(112 694)	(107 934)
Interest on trust preferred securities	---	---	(8 536)
Interest on multi-client library securitization securities	---	---	(1 685)
Interest capitalized in multi-client library (Note 15)	1 878	1 461	2 696
Total interest expense	(96 799)	(111 233)	(115 459)

NOTE 9 – OTHER FINANCIAL ITEMS, NET

Other financial items, net, consists of the following:

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Interest income	7 442	4 840	5 432
Foreign currency gain (loss)	(1 018)	(4 412)	(8 315)
Other [a]	(9 157)	(11 610)	(11 146)
Other financial items, net	(2 733)	(11 182)	(14 029)

a) Other includes additional required rental payments relating to UK leases of $7.2 million for each of the years ended December 2005 and 2004, and $6.4 million for the year ended December 31, 2003 (see Note 12).

NOTE 10 – INCOME TAXES

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

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Current taxes:			
Norwegian	519	(397)	5 025
Foreign	19 224	1 987	26 050
Deferred taxes:			
Norwegian	(24 301)	28 526	22 620
Foreign	1 185	(1 558)	(26 878)
Total	(3 373)	28 558	26 817
Net taxes related to discontinued operations	---	---	(381)
Income tax expense (benefit)	(3 373)	28 558	26 436

The net expense (benefit) for the years ended December 31, 2005, 2004, and 2003 includes $1.0 million, $0.3 million and $(6.9) million, respectively, related to contingent tax issues. Total accrued amount related to contingent tax liabilities per December 31, 2005, was $22.3 million, of which $3.1 million recorded as income taxes payable and $19.2 million as other long-term liabilities. As of December 31, 2004 such amount totaled $26.3 million, of which $1.7 million in income taxes payable and $24.6 million in other long-term liabilities.

The expense (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)	2005	2004	2003
Income (loss) before income taxes:			
Norwegian	171 986	(75 555)	(528 118)
Foreign	203 242	49 836	(263 954)
Total	375 228	(25 719)	(792 072)
Norwegian statutory rate	28%	28%	28%
Provision (benefit) for income taxes at statutory rate	105 064	(7 201)	(221 780)
Increase (reduction) in income taxes from:			
Foreign earnings taxed at other than statutory rate	(4 702)	(7 422)	24 871
Petroleum surtax [(a)]	(2 396)	14 078	16 911
Non-taxable gain on sale of subsidiary	(40 422)	---	---
Unrealized exchange losses (permanent difference)	2 431	(2 578)	4 169
Current year realization of uncertain tax position not recognized in prior years	(82 556)	---	---
Other permanent items	30 297	15 165	30 020
Current year deferred tax asset not recognized in balance sheet	(17 511)	13 469	131 983
Other	6 422	3 047	40 643
Income tax expense (benefit)	(3 373)	28 558	26 817

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%.

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

	December 31,	
(In thousands of dollars)	2005	2004
Current assets and liabilities	15 379	---
Property, equipment and long-lived assets	(51 532)	1 822
Tax losses carried forward	(447 798)	(262 458)
Deferred gains (losses)	2 921	(15 994)
Tax credits	(3 082)	(2 893)
Expenses deductible when paid	(36 934)	(68 091)
Other temporary differences	(4 294)	(6 071)
Total net deferred tax (asset) liability	(525 340)	(353 685)
Deferred tax asset not recognized in balance sheets	506 892	384 905
Net deferred tax (asset) liability in balance sheets	(18 448)	31 220
Deferred tax (asset) liability – Norwegian	(20 000)	30 854
Deferred tax (asset) liability – Foreign	1 552	366
Net deferred tax (asset) liability in balance sheets	(18 448)	31 220

Net deferred tax liability in the consolidated balance sheets is presented as:

	December 31,	
(In thousands of dollars)	2005	2004
Deferred tax liabilities (current)	1 055	2 775
Deferred tax assets (long-term)	(20 000)	---
Deferred tax liabilities (long-term)	497	28 445
Net deferred tax (asset) liability in balance sheets	(18 448)	31 220

The Company has significant tax losses carried forward and other deferred tax assets that are not recognized in the consolidated balance sheets.

The Company evaluates the amount of deferred tax asset recognized in the consolidated balance sheets by considering the evidence regarding the ultimate realization of those recorded assets. Deferred tax assets are recognized when it is more likely than not that all or some portion of deferred tax assets will be realized. Per December 31, 2005 the Company has recognized deferred tax assets of $20.0 million as available evidence, including recent profits and estimates of projected near term future taxable income, supported a more likely than not conclusion that the deferred tax assets would be realized.

Tax losses carried forward and expiration periods per December 31, 2005 are summarized as follows:

(In thousands of dollars)		
Brazil	9 476	No expiry
Norway	1 166 086	No expiry
Singapore	36 503	No expiry
UK	282 252	No expiry
U.S.	63 948	2019-2025
Other	13 677	2007/unlimited
Losses carried forward	1 571 942	

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 received a tax claim from the tax authority in Singapore relating to the years 1998 through 2002 based on the assertion that tax deduction for expenses related to investments in multi-client data library would not be allowed. The possible additional exposure is $26.8 million, of which an assessment of $7.1 million has been issued for the fiscal year 1998. Until 2003, the multi-client library was not automatically subject to tax allowances if classified as intangible asset. The Company has filed tax returns claiming tax deductions for amortization of the multi-client library as included in the financial statements. The Company is currently preparing an appeal to the Ministry of Finance against the tax claim, which would assert that costs incurred when acquiring data under an exclusive licence contract are tax deductible, while costs when acquiring data under a non-exclusive multi-client license contract are not tax deductible. Management's assessment is that it is reasonable possible, but not probable, that that the Tax Authority's view will prevail. Penalties of up to 17% of the $7.1 million that has already been assessed will accrue in 2006 if the Company does not pay the additional tax and is unsuccessful in claiming amortization.

Until January 1, 2002, a foreign subsidiary was included in the Norwegian shipping tax regime. No deferred taxes were recognized on unremitted earnings in this subsidiary prior to the withdrawal from the regime as these earnings at that time were expected to be reinvested indefinitely within the regime. A subsequent decision in 2003 to exit with effect from 2002 resulted in recognition of deferred tax liabilities of USD 37.8 million. The Norwegian Central Tax Office (CTO) has not yet finalized the 2002 tax assessment in relation to withdrawal from the Norwegian tonnage tax regime. The pending issue is related to fair value of the vessels involved. 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 11 – EARNINGS PER SHARE

Earnings per share were calculated as follows:

	Years ended December 31,		
	2005	2004	2003
Net income (loss) (in thousands of dollars)	375 036	(54 277)	(819 203)
Basic and diluted income (loss) per share	$ 6.25	$ (0.90)	$ (13.65)
Basic and diluted shares outstanding	60 000 000	60 000 000	60 000 000

PGS' Annual General Meeting on June 8, 2005, approved a three-for-one split of the PGS shares. Following the split, and as of December 31, 2005, PGS had 60 000 000 shares issued and outstanding, all of which are of the same class and have equal voting and dividend rights. Each share has a par value of NOK 10. There exists no difference between basic and diluted shares for the periods presented.

NOTE 12 – COMMITMENTS AND CONTINGENCIES

LEASES

The Company has operating lease commitments expiring at various dates through 2015. The Company also has capital lease commitments, primarily for onshore-based seismic equipment, expiring at various dates through 2008. At December 31, 2005, future minimum payments related to non-cancellable operating and capital leases with lease terms in excess of one year are as follows:

	December 31, 2005	
(In thousands of dollars)	Operating leases	Capital leases
2006	39 194	23 094
2007	27 318	7 308
2008	26 889	6 869
2009	24 613	---
2010	12 597	---
Thereafter	27 852	---
Total	158 463	37 271
Imputed interest		(3 571)
Net present value of capital lease obligations		33 700
Current portion of capital lease obligations		(20 495)
Long-term portion of capital lease obligations		13 205

The Company entered into a capital lease arrangement of $0.7 million for the year ended December 31, 2005, while there were no such new arrangements for the year ended December 31, 2004.

Future minimum payments related to non-cancellable operating leases reflect $8.2 million of sublease income for 2006, related to a time-charter of one FPSO shuttle tanker to a third party.

The future minimum payments under the Company's operating leases relate to the Company's operations as follows:

(In thousands of dollars)	December 31, 2005
Marine seismic and support vessels	6 267
Onshore seismic equipment	75
FPSO shuttle and storage tankers	56 821
Buildings	94 341
Fixtures, furniture and fittings	959
Total	158 463

Included in the minimum lease commitment for FPSO shuttle and storage tankers as presented in the table above is charter hire for the six month cancellation period for a storage tanker operating on the Banff field in the North Sea. The Company is required to charter the vessel for as long as *Ramform Banff* produces the Banff field, which could extend to 2014 depended on the customer/field operator. The maximum payment for the charter through 2014 is $97.8 million, of which only charter hire for the six month period ending June 30, 2006 is included in the table above.

Rental expense for operating leases, including leases with terms of less than one year, was $59.6 million, $61.2 million and $97.6 million for the years ended December 31, 2005, 2004 and 2003, respectively. Rental expense for operating leases are net of sub-lease income related to time charter of FPSO shuttle tankers to a third party amounting to $10.0 million, $10.3 million and $18.0 million for the years ended December 31, 2005, 2004 and 2003, respectively.

OTHER

The Company has contingencies resulting from litigation, other claims and commitments incidental to the ordinary course of business. Management believes that the probable resolution of such contingencies will not materially affect the financial position, results of operations or cash flows of the Company.

UK LEASES

The Company entered into capital leases from 1996 to 1998 relating to *Ramforms Challenger, Valiant, Viking, Victory* and *Vanguard*; the FPSO *Petrojarl Foinaven*; and the production equipment for the *Ramform Banff*. The terms for these leases ranged from 13-25 years. The Company has indemnified the lessors for the tax consequences resulting from changes in tax laws or interpretations thereof or adverse rulings by the tax authorities and for variations in actual interest rates from those assumed in the leases. There are no limits on either of these indemnities. Reference is also made to the description in Note 2 – UK Leases.

The lessors claim tax depreciation (capital allowances) on the capital expenditures that were incurred for the acquisition of the leased assets. Although the UK Inland Revenue generally deferred for a period of time agreeing to the capital allowances claimed under such leases pending the outcome of a legal proceeding in which the Inland Revenue was challenging capital allowances associated with a defeased lease, in November 2004, the highest UK court appeal ruled in favor of the taxpayer and rejected the position of the Inland Revenue. During 2005 the Inland Revenue has accepted the lessors' claims for the capital allowances under all the Company's UK leases, apart from the *Petrojarl Foinaven* lease where the Inland Revenue has raised a separate issue about the accelerated rate at which tax depreciation is available. If the Inland Revenue were successful in challenging that rate, the lessor would be liable for increased taxes on *Petrojarl Foinaven* in early periods (and decreased taxes in later years), and the Company's rental would increase. As a consequence, as of December 31, 2005, the Company recorded an accrual of 13.0 million British pounds (approximately $22.5 million) for this possible liability, which is recorded as other operating (income) expense, net, in the consolidated statements of operations and other long-term liabilities in the consolidated balance sheets. How much the rentals could increase depends primarily on how much of the asset that will be subject to a different depreciation rate. Management believes that 60 million to 70 million British pounds (approximately $104 million to $121 million) represents a worst-case scenario for this liability.

The leases are legally defeased because the Company has made up-front payments to independent third-party banks in consideration for which these banks have assumed liability to the lessor equal to basic rentals and termination sum obligations. The Company has 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. The Company amortized deferred gains of $1.1 million, $0.9 million and $0.6 million for the years ended December 31, 2005, 2004 and 2003, 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 an unrealized foreign exchange gain of $1.6 million for the year ended December 31, 2005, and unrealized exchange losses of $1.3 million and $1.5 million for the years ended December 31, 2004 and 2003, respectively. Net book value of the deferred gain amounted to 7.7 million British pounds (approximately $13.3 million) and 8.3 million British pounds (approximately $16.0 million) as of December 31, 2005 and 2004, respectively.

The defeased rental payments are based on assumed Sterling LIBOR rates between 8% and 9% per annum. If actual interest rates are greater than the assumed interest rates, the Company receives rental rebates. Conversely, if actual interest rates are less than the assumed interest rates, the Company pays rentals in excess of the defeased rental payments. Over the last several years, the actual interest rates have been below the assumed interest rates. Additional required rental payments were $7.2 million for each of the years ended December 31, 2005 and 2004, and $6.4 million for the year ended December 31, 2003. At December 31, 2005, interest rates were below the assumed interest rates. Based on forward market rates for Sterling LIBOR the net present value, using an 8% per annum discount rate, of the additional required rental payments aggregated 31.5 million British pounds (approximately $54.5 million) as of December 31, 2005. Of this amount, 1.2 million British pounds (approximately $2.0 million) was accrued at December 31, 2005. As of December 31, 2004, such accrual was 1.0 million British pounds (approximately $2.0 million).

In connection with the demerger, we have entered into other agreements, subject to final documentation, either as part of the proposed demerger plan or otherwise, to facilitate the demerger. For our UK leases on three of our Ramform seismic vessels and the production equipment for the *Ramform Banff*, we have entered into agreements, subject to final documentation, with the lessors providing for certain options with respect to the termination of the leases at reduced termination fees, subject to completion of the demerger.

BRAZIL SERVICE TAX CLAIM

The Company has an ongoing appeal process in Brazil related to municipal services tax (ISS), whether the Company is actually liable for ISS taxes and, if it is liable for such taxes, to which municipality such taxes should be paid (municipalities' levy ISS tax at different rates). The appeal relates to the period 1998 through 2001 and the potential additional exposure for this period is $8.5 million. The Company is subject to additional exposure for subsequent periods of up to $29.9 million (including potential interest and penalties). ISS is a service tax, and the Company's primary view is that licensing of multi-client data should be treated as rental of an asset rather than a service, and therefore not subject to ISS. Management's assessment is that it is reasonable possible, but not probable, that this liability will materialize. Thus no accrual has been recorded.

NOTE 13 – OTHER LONG-LIVED INTANGIBLE ASSETS

Other long-lived intangible assets consist of the following:

(In thousands of dollars)	December 31, 2005	2004
Software products	---	39
Licenses and patents	1 982	2 036
Total	1 982	2 075

NOTE 14 – PROPERTY AND EQUIPMENT, NET (INCLUDING CAPITAL LEASES)

(In thousands of dollars)	Seismic vessels/ equipment	Production vessels/ equipment	Fixtures furniture and fittings	Buildings/ other	Total
Purchase costs:					
Cost per December 31, 2004	1 083 820	1 593 701	56 616	12 280	2 746 417
Additions to costs	76 819	---	12 062	2 167	91 048
Retirements	(35 917)	(2 942)	(13 240)	(3 508)	(55 607)
Translation adjustments/other	(496)	(5 249)	(1 485)	964	(6 266)
Cost per December 31, 2005	1 124 226	1 585 510	53 953	11 903	2 775 592
Accumulated depreciation and impairments:					
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
Depreciation	65 671	39 641	6 357	1 029	112 698
Retirements	(32 235)	(2 516)	(11 757)	(3 485)	(49 993)
Impairment	4 575	---	---	---	4 575
Reversal of previous impairments	(98 034)	(211 958)	---	---	(309 992)
Translation adjustments/other	469	---	(1 911)	729	(713)
Depreciation per December 31, 2005	602 757	303 329	36 746	6 171	949 003
Impairments per December 31, 2005	60 730	449 780	---	1 200	511 710
Balance per December 31, 2005	460 739	832 401	17 207	4 532	1 314 879

The net book value of property and equipment under UK leases were $668.5 million and $636.4 million at December 31, 2005 and 2004, respectively (see Note 12).

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. An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such exists, the recoverable amount is estimated and previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. See Note 2 for further description of the accounting principle for impairments of long-lived assets. As of December 31, 2005, the Company calculated and recorded reversal of previous recognized impairments of $212.0 million relating to Production FPSOs and equipment and $98.0 million relating to seismic vessels and equipment. During 2005 the Company decided to convert its 4C crew into a streamer operations, resulting in an impairment of $4.6 million.

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 group are presented and evaluated on a combined basis.

The following table summarizes depreciation expense (see Note 6 for impairment details):

(In thousands of dollars)	Years ended December 31, 2005	2004	2003
Depreciation expense, net of amount capitalized into multi-client library	107 283	104 765	123 056
Depreciation expense capitalized into multi-client library	5 415	3 982	13 095

No interest was capitalized into property and equipment for the years ended December 31, 2005, 2004 and 2003, respectively.

For details of the estimated useful life's for the Company's property and equipment per December 31, 2005, see Note 2 for all details.

SUBSEQUENT EVENTS

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

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

NOTE 15 – 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:

	Net book value December 31,	
(In thousands of dollars)	2005	2004
Completed surveys:		
Completed during 1999, and prior years	---	15 398
Completed during 2000	6 379	22 434
Completed during 2001	54 450	112 617
Completed during 2002	23 682	38 341
Completed during 2003	19 796	33 436
Completed during 2004	4 045	10 334
Completed during 2005	7 677	---
Completed surveys	116 029	232 560
Surveys in progress	20 971	8 036
Multi-client library	137 000	240 596

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

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Impairment charges (Note 6)	---	---	241 481
Amortization expense	164 858	173 276	155 648
Interest capitalized into multi-client library	1 878	1 461	2 696
Depreciation capitalized into multi-client library	5 415	3 982	13 095

Amortization expenses for the year ended December 31, 2005 includes $66.2 million of additional non-sales related amortization. This amount includes $40.1 million in minimum amortization and $26.1 million of non-sales related amortization (impairment) to reflect reduced fair value of future sales on certain individual surveys ($25.0 million in Marine Geophysical and $1.1 million in Onshore). For the year ended December 31, 2004 the additional non-sales related amortization totaled $31.3 million of which $7.8 million was for minimum amortization and $23.5 million for non-sales related amortization (impairment) ($20.6 million in Marine Geophysical and $2.9 million in Onshore). For the year ended December 31, 2003, the Company recognized $4.0 million in minimum amortization.

For information 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.

	December 31, 2005
(In thousands of dollars)	Minimum future amortizations
During 2006	68 733
During 2007	26 012
During 2008	18 156
During 2009	9 454
During 2010	7 634
During 2011	7 011
Future minimum amortization	137 000

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 16 – OIL AND NATURAL GAS ASSETS, NET

The Company's oil and natural gas assets consisted mainly of the Company's investment in 70% of the production license 038, on the Norwegian continental shelf of the North Sea, owned by Pertra, which was sold March 1, 2005 (see Note 3). The capitalized value of the Company's remaining investment in oil and natural gas assets is as follows:

	December 31,	
(In thousands of dollars)	2005	2004
Net book value beginning of year	63 956	30 678
Capital expenditures, cash and accrued	781	81 030
Depreciation, depletion and amortization	(6 863)	(36 314)
Disposal of subsidiary (Pertra AS)	(57 776)	---
Expensed capitalized exploration costs [a]	---	(11 438)
Net book value at end of year	98	63 956

a) Classified as depreciation and amortization in the consolidated statements of operations.

The Company expensed geological and geophysical costs totaling $1.4 million, $4.9 million and $4.3 million for the years ended December 31, 2005, 2004 and 2003, respectively.

NOTE 17 – OTHER FINANCIAL ASSETS

Other financial assets consist of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Long-term receivables	16 893	14 942
Deferred debt issue costs	11 634	4 356
Governmental grants and contractual receivables	5 577	17 204
Prepaid pension contribution (Note 29)	3 029	3 603
Total	37 133	40 105

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 (see Notes 2 and 24).

NOTE 18 – ACCOUNTS RECEIVABLE, NET

Accounts receivable, net, consist of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Accounts receivable – trade	216 157	162 775
Allowance for doubtful accounts	(2 536)	(1 492)
Unbilled revenue and other receivables	67 785	40 561
Total	281 406	201 844

The change in allowance for doubtful accounts is as follows:

	December 31,	
(In thousands of dollars)	2005	2004
Beginning balance	1 492	3 468
New and additional allowances	2 067	977
Write-offs and reversals	(1 023)	(2 953)
Ending balance	2 536	1 492

NOTE 19 – OTHER CURRENT ASSETS

Other current assets consist of the following:

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

NOTE 20 SHARES AVAILABLE FOR SALE AND INVESTMENTS IN SECURITIES

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

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

NOTE 21 – RESTRICTED CASH

Restricted cash consist of:

	December 31,	
(In thousands of dollars)	2005	2004
Current:		
Bid/performance bonds	2 312	11 674
Restricted payroll withholding taxes	3 871	4 323
Other	8 311	9 480
Total restricted cash, current	14 494	25 477
Long-term – debt service reserve fund (Notes 26 and 28)	10 014	10 014
Total	24 508	35 491

NOTE 22 – SHAREHOLDER INFORMATION

As of December 31, 2005, Petroleum Geo-Services ASA had a share capital of NOK 600 million divided on a total of 60,000,000 shares, of par value NOK 10, 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.

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

	December 31, 2005	
	Total shares	Ownership percent
Citibank N.A., holder of American Depositary Shares ("ADS") (nominee) [a]	8 013 790	13.4
Morgan Stanley & Co. (nominee)	4 153 664	6.9
State Street Bank & Trust Co. (nominee)	3 258 683	5.4
Umoe Industri AS	3 037 332	5.1
Fidelity Funds-Europe	2 896 158	4.8
Morgan Stanley & Co. (nominee)	2 568 142	4.3
Bear Stearns Securities (nominee)	1 601 845	2.7
JP Morgan Chase Bank (nominee)	1 286 720	2.1
Bank of New York	1 172 492	2.0
Citibank N.A., holder of American Depositary Shares ("ADS") (nominee) [a]	1 128 707	1.9
Morgan Stanley & Co. (nominee)	1 122 349	1.9
Vital Forsikring ASA	950 090	1.6
JP Morgan Chase Bank	822 090	1.4
State Street Bank & Trust Co. (nominee)	751 088	1.3
Goldman Sachs International (nominee)	717 214	1.2
Odin Norden	550 700	0.9
Dnb Nor Norge	539 089	0.9
Skandinaviska Enskilda Banken (nominee)	537 350	0.9
Fortis Bank Luxembourg	524 216	0.9
Bank of New York	519 402	0.9
Other shareholders	23 848 879	39.5
Total	60 000 000	100.0

a) On the basis of existing depository agreements regarding owners of the ADSs, the table above does not disclose the beneficial owners 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, 2005	
	Total shares	Ownership percent
Board of Directors:		
Jens Ulltveit-Moe, *Chairperson* [a]	3 037 332	5.1
Keith Henry, *Vice Chairperson*	---	---
Francis Gugen	---	---
Harald Norvik	---	---
Rolf Erik Rolfsen	---	---
Clare Spottiswoode	---	---
Anthony Tripodo	---	---
Chief Executive Officer and Other Executive Officers:		
Svein Rennemo, *President and Chief Executive Officer*	10 038 [b]	
Gottfred Langseth, *Senior Vice President and Chief Financial Officer*	483 [b]	
Rune Eng, *President Marine Geophysical*	3 567 [b]	
Eric Wersich, *President Onshore*	717 [b]	
Espen Klitzing, *President Production*	720 [b]	

a) Controlled through Umoe Industri AS.

b) Less than 1% of the Company's share as of December 31, 2005.

NOTE 23 – SHARE-BASED COMPENSATION

In connection with the restructuring of the Company in 2003, all shares in the Company were cancelled. Accordingly, all agreements relating to 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 is summarized as follows:

	December 31, 2003	
(In thousands of options)	Options	Weighted average exercise price
Outstanding at beginning of year	4 973.5	135 NOK
Forfeited/cancelled	(4 973.5)	135 NOK
Outstanding at end of year	---	---

NOTE 24 – OTHER LONG-TERM LIABILITIES

Other long-term liabilities consist of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Accrued liabilities UK leases (Note 12)	35 793	15 983
Pension liability (Note 29)	27 828	32 364
Asset retirement obligations ("ARO") (Note 2)	20 015	58 518
Tax contingencies	19 184	25 522
Interest rate swaps (Note 28)	1 628	---
Other	1 254	955
Total	105 702	133 342

NOTE 25 – SHORT-TERM DEBT AND CURRENT PORTION OF LONG-TERM DEBT

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

	December 31,	
(In thousands of dollars)	2005	2004
Short-term debt (Note 26)	2 674	1 962
Current portion of long-term debt (Note 26)	21 732	17 828
Total	24 406	19 790

NOTE 26 – DEBT

LONG-TERM DEBT

Long-term debt consists of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Unsecured:		
10% Senior Notes, due 2010	4 624	745 949
8% Senior Notes, due 2006	---	250 000
Secured:		
Term loan, due 2012, Libor + margin (see below)	850 000	---
8.28% First Preferred Mortgage Notes, due 2011	87 930	98 920
Other loans, due 2006	1 312	8 149
Total debt	943 866	1 103 018
Less current portion	(21 732)	(17 828)
Total long-term debt	922 134	1 085 190

Aggregate maturities of long-term debt as of December 31, 2005 are as follows:

(In thousands of dollars)	December 31, 2005
Year of repayment:	
2005	21 732
2006	21 400
2007	22 540
2008	23 660
2009	29 554
Thereafter	824 980
Total	943 866

In 2005 the Company repaid its 8% Senior Notes, due 2006, aggregating $250 million with cash proceeds from the sale of Pertra and other available cash. In December 2005, the Company refinanced a majority ($741.3 million) of its 10% Senior Notes, due 2010, with $746 million outstanding and entered into new credit agreements described below. Debt redemption and refinancing costs totaled $107.3 million (including $0.4 million in write-off of deferred debt issue costs) and $9.9 million in deferred debt issue costs.

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

The Company has hedged the interest rate on 50% of the borrowings under the Term Loan by entering into interest rate swaps where the Company receives floating interest rate based on 3 months LIBOR and pays fixed interest rate payments based on LIBOR for 3 and 5 years maturities. See Note 28 for further information.

The 10% Senior Notes due 2010 ("10% Notes") bear interest at 10% per annum payable semi-annually and mature in November 2010 with no required principal payments until maturity. The 10% Notes are callable by the Company beginning in November 2007 and are callable thereafter at par plus a premium of 5% declining linearly until maturity. In December 2005, the Company refinanced and retired $741.3 million of the 10% Notes. The 10% Notes are unsecured obligations of PGS ASA.

The 8.28% First Preferred Mortgage Notes due 2011 ("8.28% Notes") bear interest at 8.28% per annum, and interest and scheduled principal amounts are payable semi-annually. The 8.28% Notes are subject to redemption at par on a pro rata basis through operation of a mandatory sinking fund on a semi-annual basis according to a schedule and are subject to optional redemption by the Company beginning in June 2006 at a redemption price equal to 100% of the principal amount plus a make whole premium that is based on U.S. treasury rates plus 0.375%. The 8.28% Notes are secured by, among other things, a mortgage on the *Ramform Explorer* and the *Ramform Challenger* seismic vessels. In addition, there is established under the indenture for the 8.28% Notes a debt service reserve fund, which was initially funded in an amount (approximately $10 million) equal to the maximum interest and sinking fund payment due on the 8.28% Notes on any payment date for such notes through December 1, 2010. Such additional amount has been invested in a funding agreement that serves as a source of funds that, together with charter hire payments made by a Company subsidiary under charters for the *Ramform Explorer* and the *Ramform Challenger* vessels, are used to make debt service payments on the 8.28% Notes. This debt service reserve fund investment is presented as long-term restricted cash in the consolidated balance sheets because funds derived from the investment will be used to make final debt service payment on the 8.28% Notes.

BANK CREDIT FACILITIES

In December 2005, the Company replaced its secured $110 million revolving credit facility, originally maturing in 2006, with a new revolving credit facility ("RCF") of $150 million. The new RCF is part of the same credit agreement as the $850 million Term Loan described above and matures in 2010. The Company may use up to $60 million of capacity under the RCF for letters of credit and may borrow U.S. dollars, or any other currency freely available in the London banking market to which the lenders have given prior consent, under the RCF for working capital and for general corporate purposes. The Company may use these letters of credit, which can be obtained in various currencies, to secure, among other things, performance and bid bonds required in our ongoing business. Borrowings under the RCF bear interest at rate equal to LIBOR plus a margin that depends on our leverage ratio. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.25%; at a leverage ratio between 2:1 and 2.25:1, the applicable margin will be 2.00%; and at a leverage ratio below 2:1, the applicable margin will be 1.75%. At December 31, 2005, $14.6 million of letters of credit were issued under the RCF and the applicable margin was 2.25% per annum. In addition, the Company may be able to borrow an additional $250 million that would be secured by the same collateral that secures the Term Loan and borrowings under the RCF.

SHORT-TERM DEBT

Net short-term debt was $2.7 million as of December 31, 2005, relating to our Onshore business. As of December 31, 2004, net short-term debt was $2.0 million, of which $1.8 million related to the purchase of the seismic vessel *Falcon Explorer*.

COVENANTS

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

- our total leverage ratio may not exceed 3.50 to 1.0 in 2006, 3.25 to 1.0 in 2007 and 3.00 to 1.0 in 2008, and may not exceed 3.00 to 1.0 at the time of our proposed separation transaction described in the Board of Directors Report,
- our consolidated interest coverage ratio (defined as the ratio of consolidated EBITDA less multi-client investments to

consolidated interest expense) must be at least 3.0 to 1.0, and

- our consolidated fixed charge coverage ratio (defined as the ratio of consolidated EBITDA less multi-client investments to consolidated fixed charges) must be at least 1.3 to 1.0.

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

The Company is in compliance with the covenants in its loan and lease agreements as of December 31, 2005.

PLEDGED ASSETS

Certain seismic vessels and seismic equipment with a net book value of $89.8 million and $55.2 million at December 31, 2005 and 2004, respectively, are pledged as security under the Company's short-term and long-term debt. In addition, under the credit agreement established in December 2005, certain shares in material subsidiaries have been pledged as security.

LETTER OF CREDIT AND GUARANTEES

The Company had aggregate outstanding letters of credit and related types of guarantees, not reflected in the accompanying consolidated financial statements, of $32.7 million (including $14.6 million described above) and $30.1 million at December 31, 2005 and 2004, respectively.

NOTE 27 – ACCRUED EXPENSES

Accrued expenses consist of the following:

	December 31,	
(In thousands of dollars)	2005	2004
Accrued employee benefits	44 864	37 659
Accrued vessel operating costs	30 074	17 080
Customer advances and deferred revenue	29 723	12 070
Forward exchange contracts (Note 28)	7 234	---
Accrued assets	7 967	5 618
Accrued commissions	7 550	9 683
Accrued interest expenses	5 778	3 394
Liabilities of business transferred under a contractual arrangement (Notes 3 and 5)	3 504	---
Other	27 633	27 169
Total	164 327	112 673

NOTE 28 – FINANCIAL INSTRUMENTS

FAIR VALUES OF FINANCIAL INSTRUMENTS

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

	December 31, 2005			December 31, 2004		
(In thousands of dollars)	Carrying amounts	Notional amounts	Fair values	Carrying amounts	Notional amounts	Fair values
Long-term debt (Note 26)	943 866	---	947 105	1 013 018	---	1 218 386
Derivatives:						
Forward exchange contracts (Note 27)	(7 234)	193 536	(7 234)	---	---	---
Interest rate swaps (cash flow hedging instruments)(Note 24)	(1 628)	425 000	(1 628)	---	---	---
Commodity derivatives	---	---	---	(2 583)	---	(2 583)

The fair values of the long-term debt instruments, forward exchange contracts and interest rate swaps are estimated using quotes obtained from dealers in such financial instruments or latest quoted prices at Bloomberg.

There is established under the indenture for the 8.28% Notes a debt service reserve fund, which was initially funded in an amount (approximately $10 million) equal to the maximum interest and sinking fund payment due on the 8.28% Notes on any payment date for such notes through December 1, 2010. Such additional amount has been invested in a funding agreement that serves as a source of funds that, together with charter hire payments made by a Company subsidiary under charters for the *Ramform Explorer* and the *Ramform Challenger* vessels, are used to make debt service payments on the 8.28% Notes. The amounts held in or payable into the debt service reserve fund will be used as part of the final payment on the Notes. The Company classifies this amount as restricted cash (long-term) in its consolidated balance sheets ($10 million).

INTEREST RATE EXPOSURE

The Company holds interest rate derivatives instruments. As of December 31, 2005, the Company had outstanding interest rate swap agreements in the aggregate notional amount of $433.6 million, of which $8.6 million either matured in January 2006 or were terminated in February 2006. As of December 31, 2005, we had entered into interest rate swaps relating to $425 million of the $850 million Term Loan and changed our interest rate exposure from floating to fixed interest rate for the $425 million notional amount. We account for these swaps as interest rate hedges. Under these interest rate swap agreements, the Company receives floating interest rate payments based on 3 month LIBOR and pays fixed interest rate payments. As to a notional amount of $150 million, a fixed rate of 4.84% will apply through December 2008. As to a notional amount of $275 million, an average rate of 4.88% will apply through December 2010. The aggregate negative fair value of these interest rate swap agreements at December 31, 2005 was approximately $1.6 million and is reported as other long-term liabilities. The same amount, is recorded as a reduction in other equity as the effective portion of the designated and qualifying hedging instrument (the interest swap).

FOREIGN EXCHANGE EXPOSURE

The Company is exposed to currency fluctuation due to a predominantly USD-based revenue stream, while the Company's expenses are incurred in various currencies. The larger expense currencies other than the USD are GBP and NOK. In 2005, the Company adopted a foreign currency hedging program by buying NOK and GBP on forward contracts. As of December 31, 2005, the Company had open forward contracts to buy GBP and NOK amounting to approximately $193.5 million with a negative fair value of $7.2 million reported as accrued expenses. As of December 31, 2004, the Company did not have any open forward exchange contracts. The currency forward contracts are not accounted for as hedges.

COMMODITY DERIVATIVES

Through February 2005, the Company operated in the worldwide crude oil market through its subsidiary Pertra AS, which was sold March 1, 2005 (see Note 3). By reason of its ownership of Pertra, the Company had exposure to fluctuations in hydrocarbon prices, which historically have fluctuated widely in response to changing market forces. Pertra's net production in 2004 (combined) was 5 317 134 barrels, with an average realized price of $35.11 per barrel. In 2003 the average realized price was $29.37 per barrel.

As of December 31, 2005 and 2004, the Company did not have any outstanding derivative commodity instruments. In the first half of 2004, we sold forward 950 000 barrels of our 2004 second half production at an estimated average of $30.50 per barrel. Of the total amount sold forward, 250 000 barrels sold forward at an average price of $29.91 per barrel were not delivered at December 31, 2004, but were delivered early January 2005. Estimated fair value of the contract at December 31, 2004 was a net liability of $2.6 million, which is included in accrued expenses in the consolidated balance sheets and revenues in the consolidated statements of operations, based on mark–to-market rates.

NOTE 29 – PENSION OBLIGATIONS

DEFINED BENEFITS PLANS

The Company has historically had defined benefit pension plans for substantially all of its Norwegian and UK employees, with eligibility determined by certain period-of-service requirements. In Norway these plans are generally funded through contributions to insurance companies. In the UK, the plans are funded through a separate pension trust. It is the Company's general practice to fund amounts to these defined benefit plans at rates that are sufficient to meet the applicable statutory requirements. As of January 1, 2005, a part of the Norwegian plans were settled eliminating future spouse and child survivor benefits. Accrued benefits as of that date were settled with annuity contracts and employees eligible under these plans received a paid-up pension for earned funds covering the spouse and child portion up to December 31, 2004. In addition the Norwegian defined benefit plans were closed for further entries and new defined contribution plans established for new employees (see separate section below). At December 31, 2005, 955 employees were participating in these plans.

Pension costs for disposed subsidiaries are included for the period up to sales closing date.

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

Change in projected benefit obligations (PBO):

	December 31,	
(In thousands of dollars)	2005	2004
Projected benefit obligations (PBO) at beginning of year	115 880	93 008
Service cost	9 445	10 198
Interest cost	5 540	5 145
Employee contributions	1 033	968
Payroll tax	(518)	198
Actuarial (gain) loss, net	10 992	(2 045)
Benefits paid	(1 382)	(1 212)
Exchange rate effects	(15 021)	9 620
Projected benefit obligations (PBO) at end of year	125 969	115 880

Change in pension plan assets:

(In thousands of dollars)	December 31, 2005	2004
Fair value of plan assets at beginning of year	71 565	53 332
Adjustment at beginning of year	(894)	(1 347)
Return on plan assets	4 878	4 130
Employer contributions	9 848	8 383
Employee contributions	1 033	968
Benefits paid	(1 382)	(1 212)
Exchange rate effects	(8 639)	7 311
Fair value of plan assets at end of year	76 409	71 565

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

(In thousands of dollars)	December 31, 2005	2004
Funded status	(47 732)	(44 315)
Unrecognized actuarial loss	21 126	15 554
Adjustment, disposal of subsidiaries	1 807	---
Net pension liability	(24 799)	(28 761)

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

(In thousands of dollars)	December 31, 2005	2004
Other financial assets (Note 17)	3 029	3 603
Other long-term liabilities (Note 24)	(27 828)	(32 364)
Net amount recognized as accrued pension liability	(24 799)	(28 761)

The accumulated benefit obligation (ABO) for all defined benefit pension plans was $111.4 million and $104.3 million as of December 31, 2005 and 2004, respectively.

Net periodic pension cost for the Company's defined benefit pension plans are summarized as follows:

(In thousands of dollars)	Years ended December 31, 2005	2004	2003
Service cost	9 445	10 198	8 792
Interest cost	5 540	5 145	4 454
Expected return on plan assets	(4 878)	(4 130)	(3 796)
Amortization of plan changes	(6 675)	---	---
Amortization of actuarial loss	823	1 119	2 142
Adjustment to actuarial loss, plan changes	2 574	---	---
Amortization of prior service cost	---	---	3
Amortization of transition obligation	---	---	20
Adjustment to minimum liability	4 927	(1 874)	---
Administration costs	105	99	---
Payroll tax	456	1 047	1 492
Net periodic pension cost	12 317	11 604	13 107

Assumptions used to determine net periodic pension costs:

	Years ended December 31,					
	2005		2004		2003	
	Norway	UK	Norway	UK	Norway	UK
Discount rate	4.8%	5.3%	5.3 %	5.3 %	6.0 %	5.3 %
Return on plan assets	5.8%	7.5%	6.3 %	7.5 %	7.0 %	7.5 %
Compensation increase	3.2%	3.0%	3.0 %	3.0 %	3.0 %	4.7 %
Annual adjustment to pensions	3.2%	3.0%	3.0 %	3.0 %	3.0 %	3.0 %

Assumptions used to determine benefit obligations at end of years presented:

	December 31, 2005		December 31, 2004	
	Norway	UK	Norway	UK
Discount rate	4.3%	4.8%	5.3 %	5.3 %
Compensation increase	3.2%	3.2%	3.0 %	3.0 %

The discount rate assumptions used for calculating pensions reflect the rates at which the obligations could be effectively settled. Observable long-term rates on governmental bonds are used as a starting point and matched with the Company's expected cash flows under the Norwegian plans. Observable long-term rates on corporate bonds are used for the UK plans. The expected long-term rate of return on plan assets is based on historical experience and by evaluating input from the trustee managing the plan's assets.

The Company's pension plan asset allocation at December 31, 2005 and 2004, by asset category, are presented by major plan group as follows:

	December 31, 2005		December 31, 2004	
(In thousands of dollars)	Norway	UK	Norway	UK
Fair value of plan assets	$38 268	$38 141	$40 111	$31 454
Debt securities	62%	---	69%	---
Equity securities	23%	100%	16%	92%
Real estate	12%	---	12%	---
Other	3%	---	3%	8%
Total	100%	100%	100%	100%

Average target allocations for Norwegian plan assets are 15-30% in equity securities, 50-70% in debt securities, 10-15% in real estate and 3-10% in other. Maturities for the debt securities at December 31, 2005, range from two weeks to 28 years with a weighted average maturity of 4.6 years. Weighted average duration for the debt securities is 3.6 years.

Management of plan assets must comply with applicable laws and regulations in Norway and the UK where the Company provides defined benefits plans. Within constraints imposed by laws and regulations, and given the assumed pension obligations and future contribution rates, the majority of assets are managed actively to obtain a long-term rate of return that at least reflects the chosen investment risk.

The Company expects to contribute approximately $7.0 million to its defined benefit pension plans in 2006. Total pension benefit payments expected to be paid to participants from the plans are as follows:

(In thousands of dollars)	
2006	1 166
2007	1 371
2008	1 545
2009	1 719
2010	1 320
2011 through 2015	15 374

DEFINED CONTRIBUTION PLANS

Substantially all employees not eligible for coverage under the defined benefit plans in Norway and the UK are eligible to participate in pension plans in accordance with local industrial, tax and social regulations. All of these plans are considered defined contribution plans.

As described above under "Defined Benefit Plan", as of January 1, 2005 the Company closed the Norwegian defined benefit plans for further entries and new defined contribution plans were established for new employees. The Company's contributions to these plans for the year ended December 31, 2005 totaled $0.2 million.

Under the Company's US defined contribution 401(k) plan, essentially all US employees are eligible to participate upon completion of certain period-of-service requirements. The plan allows eligible employees to contribute up to 100% of compensation, subject to IRS and plan limitations, on a pre-tax basis, with a 2005 statutory cap of $14,000 ($18,000 for employees over 50 years). Employee pre-tax contributions are matched by the Company as follows; the first 3% are matched at 100% and the next 2% are matched at 50% of compensation. All contributions vest when made. The employer matching contribution recognized by the Company related to the plan was $1.3 million, $1.2 million and $1.4 million for years ended December 31, 2005, 2004 and 2003, respectively. Contributions to the plan by employees for these periods were $3.3 million, $3.1 million and $3.3 million, respectively.

Aggregate employer and employee contributions under the Company's other plans for the years ended December 31, 2005, 2004 and 2003 totaled $0.6 million and $0.3 million (2005), $1.6 million and $0.4 million (2004) and $1.4 million and $0.4 million (2003).

NOTE 30 – RELATED PARTY TRANSACTIONS

At December 31, 2003 the Company owned 50% of the shares in Geo Explorer AS and had one vessel on charter from that company. The Company also held 100% of the shares in Walther Herwig AS (until December 11, 2003, the Company held 50% of the shares, but increased its shares as Walter Herwig AS was de-merged) and chartered three vessels from that company in 2003. Total lease expense recognized by the Company for the year ended December 31, 2003 was $7.4 million, while there were no lease expense for the years ended December 31, 2005 and 2004.

As of December 31, 2005, the Chairperson of the Board, Jens Ulltveit-Moe, through Umoe Industri AS, controlled a total of 3,037,332 shares in PGS. Jens Ulltveit-Moe also has a majority ownership in Knutsen OAS Shipping AS (“Knutsen”). Knutsen is chartering the MT *Nordic Svenita* and was also chartering the MT *Nordic Yukon* up to 2003 and paid $10.0 million, $10.3 million and $20.1 million to the Company under time charter contracts for the vessels in 2005, 2004 and 2003, respectively. The Company charters the vessels from an independent third party. The vessels were chartered by the Company to provide shuttle services for the Banff field, but in 2001 were chartered to Knutsen on terms approximating the Company’s terms under the third-party lease, due to low production on the Banff field. The vessel MT *Nordic Yukon* was redelivered by PGS to the vessel owner in November 2003. In addition, PGS has a contract of affreightment with Knutsen for transporting crude oil relating to the Banff field and paid $1.2 million, $0.7 million and $2.4 million to Knutsen under this contract in 2005, 2004 and 2003, respectively. Mr. Ulltveit-Moe was also the Chairperson of Unitor ASA until August 2005, a company that from time to time provides the Company with equipment for its vessels.

SUBSEQUENT EVENT

In January 2006 the Company entered into an agreement to purchase the shuttle tanker MT *Rita Knutsen* for $35 million from Knutsen OAS Shipping AS. The transaction was completed on March 9, 2006. The Company considers the vessel to be a possible FPSO solution for several upcoming projects, and the Company intends to begin a conversion when a firm contract for the ship is secured. The vessel will be operated by Knudsen OAS Shipping AS under a bareboat charter agreement until a decision to start conversion is made. Jens Ulltveit-Moe did not participate in any Board discussion relating to this transaction.

NOTE 31 – SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid during the year includes payments for:

	Years ended December 31,		
(In thousands of dollars)	2005	2004	2003
Interest, net of capitalized interest	91 724	106 731	137 633
UK lease, additional required rental payments (Note 12)	7 180	7 196	6 426
Interest on trust preferred securities / multi-client library securitization	---	---	544
Income taxes	14 572	29 751	13 096

The Company entered into capital lease agreements for new equipment aggregating $0.7 million and $0.6 million for the years ended December 31, 2005 and 2003, respectively. There were no new capital lease agreements during the year ended December 31, 2004.

NOTE 32 – 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)	2005	2004	2003
Salaries	216 304	183 769	187 295
Social security	20 222	17 250	19 844
Pension	14 388	14 395	15 774
Other benefits	12 118	22 581	36 210
Total	263 032	237 995	259 123

In addition, the Company expensed salaries and other personnel costs related to discontinued operations of $1.9 million for the year ended December 31, 2003. 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 6).

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

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

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

The Company had an average of 4 015; 3 138 and 3 690 employees during the years ended December 31, 2005, 2004 and 2003, respectively.

CHIEF EXECUTIVE OFFICER (CEO) AND OTHER EXECUTIVE OFFICERS

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

		Total compensation paid during 2005			
Name:	Position:	Fixed salary and other compensation	Bonus[a)]	Executive officer since	Share ownership
		(In dollars)			
Svein Rennemo	President and Chief Executive Officer	607 454	177 440	2002	b)
Gottfred Langseth	Senior Vice President and Chief Financial Officer	355 313	82 129	2004	b)
Rune Eng	President – Marine Geophysical	413 333	74 876	2004	b)
Eric Wersich	President – Onshore	262 350	85 259	2003	b)
Espen Klitzing	President – Production, from November 2005	54 597	---	2005	b)
Sverre Skogen	President – Production, through October 2005	189 731	72 751	2004	

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

b) Less than 1% of the Company's shares as of December 31, 2005 (see Note 22).

Included in Svein Rennemo's fixed salary and other compensation is an annual pension benefit compensation of $38 998 (equivalent to NOK 250 000). Bonus includes $126 743 (equivalent to NOK 812 500) in cash bonus and $50 697 (equivalent to NOK 325 000) of share purchase bonus. The Company also paid $57 565 in minimum requirement to a defined benefit plan (for the years 2003, 2004 and 2005). Starting in 2006, Mr. Rennemo's fixed annual pension benefit compensation, included in fixed salary, was reduced to approximately $30 000 (equivalent to NOK 200 000).

According to the Company's 2005 bonus incentive plan, 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 financial performance indicators, the Board of Directors determined that the CEO was entitled to a cash bonus of $240 246 (equivalent to NOK 1 625 000) and a share purchase bonus of $144 147 (equivalent to NOK 975 000) for 2005. The estimated bonus was accrued as of December 31, 2005. The net share purchase bonus amount, after withholding taxes, must be used to buy PGS shares at market price and held for a minimum of three years.

The CEO held 10 038 shares in PGS as of December 31, 2005. 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, with periods of notice twelve months or less.

The aggregate benefits paid to the various defined benefit plans for executive officers, excluding the CEO, as a group for 2005 was $25 373. As of December 31, 2005, executive officers, excluding the CEO, owned a total of 5 487 shares (see Note 22 for additional information). None of the executive officers held any share options in PGS.

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

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

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

BOARD OF DIRECTORS

The table below provides information about our directors as of December 31, 2005:

Name:	Position:	Director since	Term expire	Share Ownership
Jens Ulltveit-Moe	Chairperson	2002	2006	5.1 %[a)]
Keith Henry	Vice Chairperson	2003	2006	---
Francis Gugen	Director	2003	2006	---
Harald Norvik	Director	2003	2006	---
Rolf Erik Rolfsen	Director	2002	2006	---
Clare Spottiswoode	Director	2003	2006	---
Anthony Tripodo	Director	2003	2006	---

a) Controlled through Umoe Industri AS.

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

As of December 31, 2005, the total number of shares and ADS's beneficially held by directors, were 3 037 332 and none of the directors held any share options in the Company (see Note 22 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)	2005	2004	2003
Audit fees [a)]	4 112	8 460	8 267
Other attestation services [b)]	32	42	93
Fees for tax services [c)]	175	134	182
All other fees [d)]	136	---	541
Total	4 455	8 636	9 083

a) Audit fees for 2004 have been updated to reflect also fees incurred in 2005 and include fees incurred 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 have been updated to reflect also fees incurred in 2005 and 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 attestation services consist of fees for agreed upon procedures and other attestation services.

c) Fees for tax services consist of fees for tax filing services and other tax assistance services.

d) All other fees include fees for assistance in connection with Sarbanes Oxley Act, restructuring, refinancing and due diligence performed by banks in connection with the financial restructuring in 2003.

NOTE 33 – SUBSIDIARIES AND AFFILIATED COMPANIES

The ownership percentage in subsidiaries and affiliated companies as of March 23, 2006, are as follows:

Company	Jurisdiction	Shareholding and 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%
Multiklient Invest AS	Norway	100%
Petroleum Geo-Services, Inc.	United States	100%
Petroleum Geo-Services (UK) Ltd.	United Kingdom	100%
Seahouse Insurance Ltd.	Bermuda	100%
PGS Mexicana SA de CV	Mexico	100%
Dalmorneftegeofizika PGS AS	Norway	49%
Geo Explorer AS	Norway	50%
Baro Mekaniske Verksted AS	Norway	10%
Calibre Seismic Company	United States	50%
PGS Capital, Inc.	United States	100%
Diamond Geophysical Services Company	United States	100%
PGS Exploration (Nigeria) Ltd.	Nigeria	100%
PGS Data Processing Middle East SAE	Egypt	100%
PGS Data Processing, Inc.	United States	100%
Petroleum Geo-Services Asia Pacific Pte. Ltd.	Singapore	100%
PGS Australia Pty. Ltd.	Australia	100%
Atlantis (UK) Ltd.	United Kingdom	100%
PGS Egypt for Petroleum Services	Egypt	100%
Hara Skip AS	Norway	100%
PGS Exploration, SDN BHD	Malaysia	100%
PGS Exploration, Inc.	United States	100%
PGS Exploration Pty. Ltd.	Australia	100%
PGS Ocean Bottom Seismic, Inc.	United States	100%
PGS Exploration (UK) Ltd.	United Kingdom	100%
PGS Floating Production (UK) Ltd.	United Kingdom	100%
PGS Pension Trustee Ltd.	United Kingdom	100%
PGS Reservoir (UK) Ltd.	United Kingdom	100%
Atlantic Explorer Ltd.	Isle of Man	50%
Oslo Seismic Services Inc.	United States	100%
Oslo Explorer Plc	Isle of Man	100%
Oslo Challenger Plc	Isle of Man	100%
PGS Shipping (Isle of Man) Ltd.	Isle of Man	100%
PGS Onshore, Inc.	United States	100%
PGS Onshore (Canada), Inc.	Canada	100%
PGS Americas, Inc.	United States	100%
Seismic Energy Holding, Inc.	United States	100%
PGS Caspian AS	Norway	100%
PGS Multi-Client Seismic Ltd.	Jersey	100%
PGS Marine Services (Isle of Man) Ltd.	Isle of Man	100%
Golar-Nor Offshore AS	Norway	100%
Golar-Nor Offshore (UK) Ltd.	United Kingdom	100%
K/S Petrojarl I AS	Norway	98.5%
Golar-Nor (UK) Ltd.	United Kingdom	100%
Deep Gulf LLC	United States	50.1%
PGS Nopec (UK) Ltd.	United Kingdom	100%
PGS Nominees Ltd.	United Kingdom	100%
Petrojarl 4 DA	Norway	99.25%
SOH, Inc.	United States	100%
PT PGS Nusantara	Indonesia	100%
PGS Processing (Angola) Ltd.	United Kingdom	100%
Seismic Exploration (Canada) Ltd.	United Kingdom	100%
PGS Ikdam Ltd.	United Kingdom	100%
Sakhalin Petroleum Plc.	Cyprus	100%

Company *(Continues)*	Jurisdiction	Shareholding and voting rights
Ikdam Production, SA	France	40%
PGS Investigacào Petrolifera Limitada	Brazil	99%
Sea Lion Exploration Ltd.	Bahamas	100%
PGS Administración y Servicios S.A. de C.V.	Mexico	100%
PGS Servicios C.A.	Venezuela	100%
PGS Venezuela de C.A.	Venezuela	100%
PGS Overseas AS	Norway	100%
PGS Suporte Logistico e Servicos Ltda.	Brazil	100%
PGS Finance, Inc.	United States	100%
Valiant International Petroleum Ltd.	United Kingdom	24.6%
PGS Japan K.K.	Japan	100%
PGS Petrojarl Varg AS	Norway	100%
PGS Tanker AS	Norway	100%
PGS Ramform Banff Ltd.	United Kingdom	100%
PGS Ramform Banff AS	Norway	100%

Petroleum Geo-Services ASA

(Parent company unconsolidated financial statements)

STATEMENT OF OPERATIONS

(In thousands of NOK)	*Note*	Years ended December 31, 2005	2004	2003
Revenues		141 873	106 304	200 836
Cost of sales		4 539	8 511	187 640
Depreciation and amortization	*7*	9 867	6 442	5 881
Selling, general and administrative costs		189 031	234 831	375 069
Total operating expenses		203 437	249 784	568 590
Operating profit (loss)		(61 564)	(143 480)	(367 754)
Interest expense, net	*2*	(56 877)	(211 141)	(182 949)
Reversal (impairment) of shares in subsidiaries/intercompany receivable	*1, 8*	3 672 257	(13 104)	(5 078 291)
Other financial items, net	*3*	485 474	(456 523)	(398 873)
Income (loss) before income taxes		4 039 290	(824 248)	(6 027 867)
Income tax expense (benefit)	*4*	-	-	-
Net income (loss)		4 039 290	(824 248)	(6 027 867)

March 27, 2006

Jens Ulltveit-Moe
Chairperson

Clare Spottiswoode

Harald Norvik

Anthony Tripodo

Keith Henry
Vice chairperson

Rolf Erik Rolfsen

Francis Gugen

Svein Rennemo
Chief Executive Officer

Petroleum Geo-Services ASA

(Parent company unconsolidated financial statements)

BALANCE SHEET

		December 31,	
(In thousands of NOK)	*Note*	2005	2004
ASSETS			
Long-term assets:			
Property and equipment, net	*7*	36 972	37 831
Shares in subsidiaries	*1, 8*	4 705 388	1 851 257
Intercompany receivables	*1*	6 732 862	5 941 944
Other financial assets	*9*	90 475	38 786
Total long-term assets		11 565 697	7 869 818
Current assets:			
Receivables		65 330	402
Short-term intercompany receivables		58 217	47 981
Other current assets		14 114	6 267
Restricted cash		1 605	2 083
Cash and cash equivalents		437 055	452 483
Total current assets		576 321	509 216
Total assets		12 142 018	8 379 034
LIABILITIES AND SHAREHODLERS' EQUITY			
Shareholders' equity:			
Paid in capital:			
Common stock; 60,000,000 shares authorized, issued and outstanding, par value NOK 10, at December 31, 2005 and 20,000,000 shares authorized, issued and outstanding, par value NOK 30, at December 31, 2004		600 000	600 000
Additional paid in capital		1 104 515	1 104 515
Total paid in capital		1 704 515	1 704 515
Other equity		4 028 292	-
Total shareholders' equity	*10*	5 732 807	1 704 515
Debt:			
Pension liabilities	*5*	4 593	4 873
Other long-term debt:			
Intercompany debt	*11*	475 526	502 782
Long-term debt	*11, 12*	5 723 110	6 106 162
Other long-term liabilities		37 747	24 555
Total other long-term debt		6 236 383	6 633 499
Current liabilities:			
Short-term debt and current portion of long-term debt	*11*	57 493	-
Short-term intercompany debt		9 403	5 856
Accounts payable		17 940	14 941
Accrued expenses	*12, 13*	83 399	15 350
Total current liabilities		168 235	36 147
Total liabilities and shareholders' equity		12 142 018	8 379 034
Warranties	*15*		

Petroleum Geo-Services ASA

(Parent company unconsolidated financial statements)

STATEMENT OF CASH FLOWS

	Years ended December 31,		
(In thousands of NOK)	2005	2004	2003
Cash flows (used in) provided by operating activities:			
Net income (loss)	4 039 290	(824 248)	(6 027 867)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization charged to expense	9 867	6 442	5 881
(Reversal) impairment of shares in and loan to subsidiaries, net and net gain on sale of subsidiaries	(4 650 041)	13 104	5 078 291
Premium debt redemption and cost of refinancing expensed	709 515	-	-
Items classified as investment/financing activities	-	(31 174)	41 906
Unrealized foreign exchange (gain) loss	(220 392)	449 608	(320 571)
Changes in current assets and current liabilities	8 162	(173 923)	(166 810)
Net (increase) decrease in restricted cash	478	1 005	(1 850)
Other items	15 747	11 090	85 272
Net cash used in operating activities	(87 374)	(548 096)	(1 305 748)
Cash flows (used in) provided by investing activities:			
Investments in property and equipment	(9 008)	(15 458)	-
Proceeds from sale of subsidiares, net	923 420	-	373 525
Investment in subsidiaries and changes in intercompany receivables	746 768	898 195	551 602
Net cash provided by investing activities	1 661 180	882 737	925 127
Cash flows (used in) povided by financing activities:			
Proceeds from issuance of long-term debt	5 652 330	-	-
Repayment of long-term debt	(6 503 556)	(33 602)	126 058
Receipts of dividend	-	31 174	68 004
Premium debt redemption, deferred loan costs and reorganization fees	(775 037)	(24 340)	-
Net cash (used in) provided by financing activities	(1 626 263)	(26 768)	194 062
Net increase (decrease) in cash and cash equivalents	(52 457)	307 873	(186 559)
Effect of exchange rate changes on cash and cash equivalents	37 029	(69 933)	(14 353)
Cash and cash equivalents at beginning of year	452 483	214 543	415 455
Cash and cash equivalents at end of year	437 055	452 483	214 543

Petroleum Geo-Services ASA

(Parent company unconsolidated financial statements)

NOTES TO FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Petroleum Geo-Services ASA ("PGS 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"). PGS ASA applies the same accounting policies as described in Note 2 in the notes to the consolidated financial statements, except that it applies 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 8) are presented at cost less any impairment. When the value of estimated future cash flows is lower than the carrying value in the subsidiaries, PGS ASA recognizes impairment charges on investments in subsidiaries and intercompany receivables. If and when estimated recoverable amounts increase, 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)	2005	2004	2003
Interest income, external	20 797	5 278	3 058
Interest income, intercompany	1 073 607	659 610	749 380
Interest expense, external [a)]	(560 493)	(633 765)	(676 404)
Interest expense, intercompany	(590 788)	(242 264)	(258 983)
Total	(56 877)	(211 141)	(182 949)

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)	2005	2004	2003
Net gain (loss) on sale of subsidiaries	977 784	---	(102 726)
Foreign currency gain (loss)	219 073	(462 251)	(267 979)
Debt redemption and refinancing costs	(709 515)	---	---
Dividends received	---	31 174	68 004
Write-off of deferred debt issue costs and issue discounts	(2 528)	---	(94 829)
Other	660	(25 446)	(1 343)
Total	485 474	(456 523)	(398 873)

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)	2005	2004	2003
Income (loss) before income taxes	4 039 290	(824 248)	(6 027 867)
Norwegian statutory tax rate	28%	28%	28%
Provision (benefit) for income taxes at the statutory rate	1 131 001	(230 789)	(1 687 803)
Increase (reduction) in income taxes from:			
Non-taxable gain on sale of shares in subsidiary	(273 780)	---	---
(Reversal) impairment of shares in subsidiaries	(816 477)	289 828	---
Other permanent items	41 551	394 615	441 937
Change deferred tax asset not recognized in balance sheet	(82 295)	(453 654)	1 245 866
Income tax expense (benefit)	---	---	---

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. PGS ASA has not recorded any net deferred tax assets due to the considerable uncertainty regarding future utilization.

The tax effects of PGS ASA's temporary differences are summarized as follows:

	December 31,	
(In thousands of NOK)	2005	2004
Temporary differences related to:		
Property and equipment	5 791	2 185
Pension liabilities	(999)	(1 316)
Intercompany receivables	(413 676)	(625 432)
Unrealized losses	(24 270)	(6 875)
Shares in foreign subsidiaries (CFC's)	(81 073)	(97 011)
Tax losses carried forward	(1 232 841)	(243 237)
Deferred tax liability (asset)	(1 747 068)	(971 686)
Deferred tax asset not recognized in balance sheet	1 747 068	971 686
Deferred tax liability (asset), net	---	---

NOTE 5 – PENSION OBLIGATIONS

DEFINED BENEFIT PLAN

PGS ASA sponsors a defined benefit pension plan for its Norwegian employees, comprising 19 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 PGS ASA's general practice to fund amounts to this defined benefit plan, which is sufficient to meet the applicable statutory requirements. As of January 1, 2005, a part of the plan was settled eliminated future spouse and child survivor benefits. Accrued benefits as of that date were settled with annuity contracts and employees eligible under these plans received a paid-up pension for earned funds covering the spouse and child portion up to December 31, 2004. In addition the defined benefit plan was closed for further entries and new defined contribution plan established for new employees (see separate section below).

Net periodic pension costs for PGS ASA's defined benefit pension plan are summarized as follows:

	Years ended December 31,		
(In thousands of NOK)	2005	2004	2003
Service costs	2 369	2 661	2 282
Interest cost	867	995	1 062
Expected return on plan assets	(732)	(685)	(781)
Amortization of plan change	(3 372)	---	---
Amortization of actuarial loss	182	209	201
Adjustment to minimum liability	1 507	---	---
Administrative costs	84	87	---
Payroll tax	128	461	378
Net periodic pension costs	1 033	3 728	3 142

The pension liabilities have been calculated based on the underlying economic realities. The aggregate funded status on the plan and amounts recognized in PGS ASA's balance sheet is as follows:

	December 31,	
(In thousands of NOK)	2005	2004
Funded status	(10 628)	(10 205)
Unrecognized actuarial loss	7 575	6 067
Accrued payroll tax	(431)	(583)
Net amount recognized as accrued pension liability	(3 484)	(4 721)

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

	December 31,	
(In thousands of NOK)	2005	2004
Other financial assets	1 109	152
Pension liabilities	(4 593)	(4 873)
Net amount recognized as accrued pension liability	(3 484)	(4 721)

Assumptions used to determine benefit obligations:

	Years ended December 31,		
	2005	2004	2003
Discount rate	4.8%	5.3%	6.0%
Return on plan assets	5.8%	6.3%	7.0%
Compensation increase	3.2%	3.0%	3.0%
Annual adjustment to pensions	3.2%	3.0%	3.0%

DEFINED CONTRIBUTION PLAN

As described above under "Defined Benefit Plan", as of January 1, 2005, PGS ASA closed the defined benefit plan for further entries and a new defined contribution plan was established for new employees. PGS ASA's contributions to this plan for the year ended December 31, 2005 totaled NOK 105 742.

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, 2005 are as follows:

(In thousands of NOK)	December 31, 2005
2006	5 107
2007	5 107
2008	5 107
2009	5 107
2010	5 107
Total	25 535

Rental expense for operating leases, including leases with terms of less than one year, was NOK 6.4 million, NOK 18.3 million and NOK 32.0 million for the years ended December 31, 2005, 2004 and 2003, respectively.

NOTE 7 – PROPERTY AND EQUIPMENT, NET

Property and equipment, net consists of fixtures, furniture and fittings. Net book value of property and equipment is as follows:

	December 31,		
	2005	2004	2003
Purchase costs:			
Accumulated cost at beginning of year	75 750	60 779	61 451
Additions to costs	9 008	15 458	---
Retirements	---	(487)	(672)
Accumulated cost at end of year	84 758	75 750	60 779
Accumulated depreciation:			
Accumulated depreciation at beginning of year	37 919	31 965	26 357
Depreciation	9 867	6 442	5 881
Retirements	---	(488)	(273)
Accumulated depreciation at end of year	47 786	37 919	31 965
Balance per December 31	36 972	37 831	28 814

Property and equipment is depreciated over 3 to 5 years.

NOTE 8 – SHARES IN SUBSIDIARIES

Shares in subsidiaries are recognized in PGS ASA's balance sheet at cost less any impairment:

	Registered office	Number of shares	Total share capital		Share-holding a)	Par value		Book value as of December 31, 2005 *(In thousands of NOK)*
PGS Geophysical AS	Oslo	1 440 000	NOK	144 000 000	100%	NOK	100	1 124 520
PGS Exploration (Nigeria) Ltd.	Nigeria	2 000 000	USD	2 000 000	100%	USD	1	---
Petroleum Geo-Services, Inc.	Houston	1 000	USD	1 000	100%	USD	1	698 838
Petroleum Geo-Services (UK) Ltd.	London	222 731 726	GBP	222 731 726	100%	GBP	1	595 195
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	318 305
PGS Shipping AS	Oslo	4 733 975	NOK	189 359	100%	NOK	0.04	803 320
Petroleum Geo-Services Asia Pacific Pte. Ltd.	Singapore	100 000	SGD	700 032 148	100%	SGD	1	516 431
PGS Investigacào Petrolifera Limitada	Brazil	---	BRL	5 000	99%	BRL	---	43 058
PGS Mexicana SA de CV	Mexico	118 000 000	MXN	118 000 100	100%	MXN	1	76 182
PGS Venezuela de C.A.	Venezuela	7 000	BS	7 000 000	100%	BS	1 000	---
PGS Production AS	Trondheim	187 283 310	NOK	187 283 310	100%	NOK	1	---
Hara Skip AS	Oslo	1 066 016	NOK	106 601 600	100%	NOK	100	487 704
Oslo Seismic Services Ltd.	Isle of Man	1	USD	1	100%	USD	1	33 570
PGS Overseas AS	Oslo	100	NOK	100 000	100%	NOK	1 000	100
PGS Australia Pty. Ltd.	Perth	---	---	---	100%	---	---	---
Total								4 705 388

a) Voting rights are equivalent to shareholding for all companies.

In March 2005, PGS ASA sold its wholly owned oil and natural gas subsidiary Pertra AS to Talisman Energy (UK) Ltd., and recognized a NOK 976.5 million gain from the sale. See Note 3 in the consolidated financial statements for further information regarding this sale.

In August 2005, the PGS ASA entered into an agreement to sell its wholly owned subsidiary PGS Reservoir AS to Reservoir Consultants Holding AS ("RCH"), which is controlled by a group of former employees. PGS ASA recorded an estimated gain of NOK 1.3 million for this transaction. For further information see Note 3 in the consolidated financial statements.

For additional information on impairment of shares in subsidiaries, see Note 1.

NOTE 9 – OTHER FINANCIAL ASSETS

Other financial asset consists of:

	December 31,	
(In thousands of NOK)	2005	2004
Deferred debt issue costs	65 031	14 156
Long-term receivables	25 444	24 630
Total	90 475	38 786

Deferred debt issue costs were until December 16, 2005, expensed on a straight-line basis over the period up until maturity. These costs are included as part of external interest expense in the statement of operations (see Note 2). After the refinancing of debt, which came into effect on December 16, 2005, deferred debt issue cost relating to long-term debt will be expensed using the effective interest method over the period the associated debt is outstanding. Deferred debt issue cost relating to revolving credit facility is expensed on a straight-line basis over the period up until maturity.

NOTE 10 – SHAREHOLDERS' EQUITY

Changes in the shareholders' equity for the years ended December 31, 2005 and 2004 are as follows:

(In thousands of NOK, except for share data)	Number of shares	Paid-in capital: Common stock	Paid-in capital: Share premium reserve	Other equity	Shareholders' equity
Balance at December 31, 2003	20 000 000	600 000	1 928 763	---	2 528 763
Net loss	---	---	(824 248)	---	(824 248)
Balance at December 31, 2004	20 000 000	600 000	1 104 515	---	1 704 515
Share split June 8, 2005	40 000 000	---	---	---	---
Revaluation interest rate swaps	---	---	---	(10 998)	(10 998)
Net income	---	---	---	4 039 290	4 039 290
Balance at December 31, 2005	60 000 000	600 000	1 104 515	4 028 292	5 732 807

As of December 31, 2005, Petroleum Geo-Services ASA had a share capital of NOK 600 million divided on a total of 60 000 000 shares, of par value NOK 10, each fully paid in. All shares have equal voting rights and are entitled to dividends. Any distribution of PGS ASA's equity is dependent on the approval of the shareholders, and the ability to make distributions is limited by certain debt covenants and Norwegian Corporate Law (see Note 26 to the consolidated financial statements). A listing of PGS ASA's largest shareholders is provided in Note 22 in the consolidated financial statements.

NOTE 11 – DEBT

LONG-TERM DEBT

Long-term debt consists of the following:

(In thousands of NOK)	December 31, 2005	December 31, 2004
Secured:		
Term loan, due 2012, Libor + margin ($850.0 million)	5 749 323	---
Unsecured:		
10% Senior Notes, due 2010 ($745.9 million)	31 280	4 573 412
8% Senior Notes, due 2006 ($250.0 million)	---	1 532 750
Total debt	5 780 603	6 106 162
Less current portion	(57 493)	---
Total long-term debt	5 723 110	6 106 162

In December 2005, PGS ASA entered into a new credit agreement, establishing a term loan of NOK 5.7 billion ($850 million) ("Term Loan") and a revolving credit facility ("RCF") of NOK 1.0 billion ($150 million). The Term Loan amortizes 1% per annum, with the remaining balance due in 2012, and bears interest at a rate of LIBOR plus a margin that depends on our leverage ratio. Leverage ratio, as defined in the Credit Agreement, is the ratio of consolidated Indebtedness to Consolidated EBITDA reduced by multi-client investments made for the period in question. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.5% per annum. Below that level, the margin will be 2.25% per annum. The credit agreement generally requires the Company to apply 50% of excess cash flow to repay outstanding borrowings for periods when our leverage ratio exceeds 2:1.

Excess cash flow for any period is defined as net cash flow provided by operating activities during that period less capital expenditures made in that period or committed to be made in the next period, less debt service payments and less accrued income taxes to be paid in the next period. PGS ASA can make optional payments to reduce the principal at no penalty. The Term Loan is an obligation of PGS ASA and PGS Finance Inc. as co-borrowers, is secured by pledges of shares of certain material subsidiaries and is guaranteed by certain material subsidiaries.

PGS ASA has hedged the interest rate on 50% of the borrowings under the Term Loan by entering into interest rate swaps where PGS ASA receives floating interest rate based on 3 months LIBOR and pays fixed interest rate for 3 and 5 years maturities. See Note 12 for further information.

The 10% Senior Notes, due 2010 ("10% Notes") bear interest at 10% per annum payable semi-annually and mature in November 2010 with no required principal payments until maturity. The 10% Notes are callable by PGS ASA beginning in November 2007 and are callable thereafter at par plus a premium of 5% declining linearly until maturity. In December 2005, PGS ASA refinanced and retired $741.3 million of the 10% Notes (equivalent to NOK 4.9 billion converted to the exchange rate at the time of redemption). The 10% Notes are unsecured obligations of PGS ASA.

BANK CREDIT FACILITIES

In December 2005, the PGS ASA replaced its secured $110 million revolving credit facility, originally maturing in 2006, with a new revolving credit facility ("RCF") of NOK 1.0

billion ($150 million). The new RCF is part of the same credit agreement as the $850 million Term Loan described above and matures in 2010. PGS ASA may use up to NOK 405.8 million ($60 million) of capacity under the RCF for letters of credit and may borrow U.S. dollars, or any other currency freely available in the London banking market to which the lenders have given prior consent, under the RCF for working capital and for general corporate purposes. PGS ASA may use these letters of credit, which can be obtained in various currencies, to secure, among other things, performance and bid bonds required in our ongoing business. Borrowings under the RCF bear interest at rate equal to LIBOR plus a margin that depend on our leverage ratio. At a leverage ratio of 2.25:1 or greater, the applicable margin will be 2.25%; at a leverage ratio between 2:1 and 2.25:1, the applicable margin will be 2.00%; and with leverage ratio below 2:1, the applicable margin will be 1.75%. At December 31, 2005, NOK 98.8 million ($14.6 million) of letters of credit were issued under the RCF and the applicable margin was 2.25% per annum.

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 loan and lease agreements include various covenants. See Note 26 in the consolidated financial statements for additional information.

NOTE 12 – FINANCIAL INSTRUMENTS

FAIR VALUES OF FINANCIAL INSTRUMENTS

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

	December 31, 2005			December 31, 2004		
(In thousands of NOK)	Carrying amounts	Notional amounts	Fair values	Carrying amounts	Notional amounts	Fair values
Long-term debt (Note 11)	5 780 603	---	5 784 669	6 106 162	---	6 777 095
Derivatives:						
Forward exchange contracts	(48 931)	1 309 060	(48 931)	---	---	---
Interest rate swaps (cash flow hedging instruments)	(11 012)	2 932 831	(11 012)	---	---	---

The fair values of the long-term debt instruments, forward exchange contracts and interest rate swaps are estimated using quotes obtained from dealers in such financial instruments or latest quoted prices at Bloomberg.

INTEREST RATE EXPOSURE

PGS ASA holds interest rate derivative instruments. As at December 31, 2005, PGS ASA had outstanding interest rate swap agreements in the aggregate notional amount of NOK 2.9 billion ($433.6 million) of which NOK 58.2 million ($8.6 million) either matured in January 2006 or were terminated in February 2006. As of December 31, 2005, we have interest rate swaps relating to NOK 2.9 billion ($425.0 million) of the $850 million Term Loan and changed our interest rate exposure from floating to fixed interest rate for the NOK 2.9 billion ($425.0 million) notional amount. We account for these swaps as interest rate hedges. Under these interest rate swap agreements, PGS ASA receives floating interest rate payments based on 3 month LIBOR and pays fixed interest rate payments. As to a notional amount of NOK 1.0 billion ($150 million), a fixed rate of 4.84% will apply through December 2008. As to a notional amount of NOK 1.9 billion ($275 million), an average fixed rate of 4.88% will apply through December 2010. The aggregate negative fair value of these interest rate swaps agreements at December 31, 2005 was approximately NOK 11.0 million ($1.6 million) and is reported as other long-term liabilities.

FOREIGN EXCHANGE EXPOSURE

The Company is exposed to currency fluctuation due to a predominantly USD-based revenue stream, while the Company's expenses are incurred in various currencies. The larger expense currencies beside the USD are GBP and NOK. In 2005, the Company adopted a foreign currency hedging program by buying NOK and GBP on forward contracts. As of December 31, 2005, PGS ASA had open forward contracts to buy GBP and NOK amounting to approximately NOK 1.3 billion ($193.5 million) with a negative fair value of NOK 48.9 million ($7.2 million) reported as accrued expenses. As of December 31, 2004, PGS ASA did not have any open forward exchange contracts. The currency forward contracts are not accounted for as hedges and expensed in the statement of operations.

NOTE 13 – ACCRUED EXPENSES

Accrued expenses consist of the following:

	December 31,	
(In thousands of NOK)	2005	2004
Accrued unrealized loss hedging (Note 12)	48 931	---
Accrued interest expense	12 625	---
Other	21 843	15 350
Total	83 399	15 350

NOTE 14 – 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 and general and administrative costs consist of:

	Years ended December 31,		
(In thousands of NOK)	2005	2004	2003
Salaries	30 568	33 265	42 564
Social security	5 618	5 520	4 779
Pension	1 033	3 728	3 142
Other benefits	7 209	1 754	15 377
Total	44 428	44 267	65 862

The Company had an average of 25 employees in 2005. Average number of employees for 2004 and 2003 were 23 and 24, 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 32 to the consolidated financial statements.

REMUNERATION TO AUDITOR

Fees for audit and other services provided by PGS ASA's auditor are as follows (exclusive VAT and inclusive out of pocket expenses):

	Years ended December 31,		
(In NOK)	2005	2004	2003
Total audit fees [a)]	7 912 538	34 261 104	42 258 889
Fees for tax services [b)]	89 890	8 500	---
Other services [c)]	845 518	---	3 784 067
Total	8 847 946	34 269 604	46 042 956

a) Fees for 2004 include fees 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 2004 include fees incurred 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) Include fees for tax filing services and other tax assistance.

c) Other services for 2003 include fees for assistance in connection with restructuring and due-dilligence performed by banks.

NOTE 15 – 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 26 to the consolidated financial statements.

ERNST & YOUNG

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Medlemmer av Den norske Revisorforening

To the General Meeting of
Petroleum Geo-Services ASA

Auditor's report for 2005

We have audited the annual financial statements of Petroleum Geo-Services ASA as of 31 December 2005, showing a profit of NOK 4,039,290,000 for the Parent Company and a profit of USD 375,036,000 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 allocation of the profit. The financial statements comprise the financial statements for the Parent Company and the Group. The financial statements of the Parent Company comprise the balance sheet, the statements of operations and cash flows and the accompanying notes. The financial statements of the Group comprise the balance sheet, the statements of operations and cash flows, the statement of changes in shareholders' equity and the accompanying notes. The regulations of the Norwegian Accounting Act and accounting standards, principles and practices generally accepted in Norway have been applied in the preparation of the financial statements of the Parent Company and the Group. 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 laws, regulations and auditing standards and practices generally accepted in Norway, including the auditing standards adopted by the Norwegian Institute of Public Accountants. Those auditing standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. 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 of the Parent Company and the Group are prepared in accordance with laws and regulations and present fairly, in all material respects the financial position of the Company and the Group as of 31 December 2005, 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 record and document the accounting information as required by law and generally accepted bookkeeping practice in Norway
- the information in the Directors' report concerning the financial statements, the going concern assumption, and the proposal for the allocation of the profit is consistent with the financial statements and complies with law and regulations.

Oslo, 27 March 2006
ERNST & YOUNG AS

Jan Egil Haga
State Authorised Public Accountant (Norway)
(sign.)

Note: The translation to English has been prepared for information purposes only.

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