SWIFT ENERGY CO
Form 10-K
March 02, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2005
Commission File Number 1-8754
SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

Texas	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

16825 Northchase Dr., Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

Title of Class:	Exchanges on Which Registered:
Common Stock, par value $.01 per share	New York Stock Exchange, Inc.
	Pacific Exchange, Inc.

Securities registered pursuant to Section 12(g) of the Act: None

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934. Yes o No þ

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

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

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of June 2005 was approximately $998,652,215.

The number of shares of common stock outstanding as of January 31, 2006 was 29,061,106.

Documents Incorporated by Reference

Document	**Incorporated as to**
Proxy Statement for the Annual	Part II, Item 5
Meeting of Shareholders to be held May 9, 2006	Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

(1) Incorporated by reference from Proxy Statement for the Annual Meeting of Shareholders to be held May 9, 2006.

PART I

Items 1 and 2. Business and Properties

See pages 25 and 26 for explanations of abbreviations and terms used herein.

General

Swift Energy Company is engaged in developing, exploring, acquiring, and operating oil and gas properties, with a focus on oil and natural gas reserves onshore and in the inland waters of Louisiana and Texas and onshore in New Zealand. Swift Energy was founded in 1979 and is headquartered in Houston, Texas. At year-end 2005, we had estimated proved reserves of 761.8 Bcfe with a PV-10 Value of $3.2 billion (PV-10 is a non-GAAP measure, see the section titled Oil and Natural Gas Reserves in our Business and Properties section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). Our proved reserves at year-end 2005 were comprised of approximately 51% crude oil, 38% natural gas, and 11% NGLs, of which 50% were proved developed. Our proved reserves are concentrated 52% in Louisiana, 31% in Texas, 16% in New Zealand, and 1% in other states.

We currently focus primarily on development and exploration of fields in three domestic regions and in New Zealand:

South Louisiana Region
Lake Washington Area
Bay de Chene Area
Cote Blanche Island Area

South Texas Region
AWP Olmos Area
Garcia Ranch Area

Toledo Bend Region
Brookeland Area
Masters Creek Area
South Bearhead Creek Area

New Zealand Region
Rimu/Kauri Area
TAWN Area

Competitive Strengths and Business Strategy

Our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to achieve our goals. Our primary goals for the next five years are to increase proved oil and natural gas reserves at an average rate of 5% to 10% per year and to increase production at an average rate of 7% to 12% per year.

Demonstrated Ability to Grow Reserves and Production

Although we have had slight decreases in the last two years, we have grown our proved reserves from 629.4 Bcfe to 761.8 Bcfe over the five-year period ended December 31, 2005. Over the same period, our annual production has grown from 42.4 Bcfe to 59.6 Bcfe and our annual net cash provided by operations has increased from $128.2 million to $285.3 million. Our growth in reserves and production over this five-year period has resulted primarily from drilling activities in our four core regions combined with producing property acquisitions. More recently, we increased our production by 2% during 2005 as compared to 2004 production. During 2005, our total proved reserves decreased by 5%, primarily due to a slowdown in drilling activity in Lake Washington as a result of

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Hurricane Katrina. Based on our long-term historical performance and our business strategy going forward, we believe that we have the opportunities, experience, and knowledge to grow both our reserves and production.

Balanced Approach to Growth

Our strategy is to increase our reserves and production through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions and strategic opportunities. In general, we focus on drilling in our anchor assets and diversity properties in each of our four regions when oil and natural gas prices are strong. When prices weaken and the per unit cost of acquisitions becomes more attractive, or a strategic opportunity exists, we shift our focus toward acquisitions. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. Over the five-year period ended December 31, 2005, we replaced 149% of our production at an average cost of $2.44 per Mcfe. More recently, we replaced 36% of our 2005 production. For 2006, we are targeting total production to increase 14% to 18% and proved reserves to increase 5% to 8% over 2005 levels.

Our 2006 capital expenditures are currently budgeted at $300 million to $325 million, net of approximately $5 million to $10 million of non-core property dispositions. Approximately 85% of the budget is targeted for domestic activities, with about 15% planned for activities in New Zealand. We plan to spend $175 million to $195 million in our South Louisiana region, which includes Lake Washington, Bay de Chene, and Cote Blanche Island. Of this amount, approximately $40 million to $50 million will be focused on activities in Bay de Chene and Cote Blanche Island and includes approximately $11 million designated for the Cote Blanche Island 3-D seismic acquisition planned for 2006. No acquisitions are currently included in our 2006 capital budget. We expect our 2006 capital expenditures will initially be at the low end of the budgeted range, and depending on commodity prices and operational performance, they may increase to the high end of the range during the course of the year. We anticipate 2006 capital expenditures to approximate our cash flow provided from operating activities during 2006.

Reserves Replacement Ratio and Reserves Replacement Cost

Historically we have added proved reserves through both our drilling and acquisition activities. We believe that this strategy will continue to add reserves for us over the long-term, however, external factors beyond our control, such as adverse weather conditions, commodity market factors, and governmental regulations, could limit our ability to drill wells and acquire proved properties in the future. We calculate and analyze reserves replacement ratios and costs to use as benchmarks against certain of our competitors. These ratios and costs are limited in use by the inherent uncertainties in the reserves estimation process, and other factors discussed below. We have included below a table listing the vintages of our proved undeveloped reserves in the table titled Proved Undeveloped Reserves, and believe this table will provide an understanding of the time horizon required to convert proved undeveloped reserves to oil and gas production. Our reserves additions for each year are estimates. Reserve volumes can change over time and, therefore cannot be absolutely known or verified until all volumes have been produced and a cumulative production total for a well or field can be calculated. Many factors will impact our ability to access these reserves, such as availability of capital, commodity prices, new and existing government regulations, competition within our industry, the requirement of new or upgraded infrastructure at the production site, and technological advances.

The reserves replacement ratio is calculated using reserves replacement volumes divided by production volumes during a specific period. The reserves replacement volumes used in this calculation are listed in the Supplemental Information (Unaudited) section of this report, specifically in a table titled Supplemental Reserves Information. Within this table there are categories titled Revisions of previous estimates, Purchases of minerals in place and Extensions, discoveries, and other additions, which when added, total the reserves replacement volumes. Production volumes are also listed in the same table, and these production volumes are also used in the reserves replacement ratio calculation.

The reserves replacement cost is calculated using reserves replacement volumes divided into acquisition, exploration, and development costs incurred during a specific period. Our acquisition, exploration, and development costs are listed in the Supplemental Information (Unaudited) section of this report, specifically in a table titled Costs Incurred. Development costs as defined by Securities and Exchange Commission rules, include costs incurred to obtain access to proved reserves and provide facilities for extracting, treating, gathering and storing

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the oil and gas. Development costs thus include well costs for our development wells and facility costs, such as those facility and platform costs we have incurred in our Lake Washington area over the past several years. Costs incurred to explore and develop reserves may extend over several years. We believe a reserves replacement cost estimate is more meaningful when calculated over several periods. Future development costs from prior years are included in this calculation to the extent that they have been included in our actual costs incurred.

Concentrated Focus on Regions with Operational Control

The concentration of our operations in four regions allows us to realize economies of scale in drilling and production by enabling us to manage larger producing fields with less personnel while minimizing incremental costs of increased drilling and completions. Each of our four regions includes at least one anchor asset, previously termed a core area, and several diversity properties that are targeted for future growth. Our average lease operating costs, excluding taxes, were $0.79, $0.71, and $0.64 per Mcfe in 2005, 2004, and 2003, respectively. This concentration allows us to utilize the experience and knowledge we gain in these areas to continually improve our operations and guide us in developing our future activities and in operating similar type assets. For example, in our South Louisiana region, we will apply the experience we have gained in Lake Washington to our Bay de Chene and Cote Blanche Island properties acquired at the end of 2004, which are also situated around salt domes. The value of this concentration is enhanced by our operating 95% of our proved oil and natural gas reserves base as of December 31, 2005. Retaining operational control allows us to more effectively manage production, control operating costs, allocate capital, and time field development.

Develop Under-Exploited Properties

We are focused on applying advanced technologies and recovery methods to areas with known hydrocarbon resources to optimize our exploration and exploitation of such properties as illustrated in our four regions. For instance, the Lake Washington field was discovered in the 1930s. We acquired our properties in this area for $30.5 million in 2001. Since that time, we have increased our average daily net production from less than 700 BOE to 13,100 BOE for the quarter ended December 31, 2005. We have also increased our proved reserves in the area from 7.7 million BOE, or 46.2 Bcfe, to approximately 39.8 million BOE or 238.9 Bcfe, as of December 31, 2005. Additionally, on our original 100,000 acre New Zealand permit, only two wells had been drilled at the time that we acquired our interest. We have drilled 42 wells in New Zealand since 1999. When we first acquired our interests in AWP Olmos, Brookeland, and Masters Creek, these areas also had significant additional development potential. Our properties in the Bay de Chene and Cote Blanche Island fields hold mainly proved undeveloped reserves and we plan to begin our initial development activities of these properties in 2006. We intend to continue acquiring large acreage positions where we can grow production by applying advanced technologies and recovery methods using our experience and knowledge developed in our four regions.

Capitalize on the Near Term Depletion of New Zealand s Largest Gas Field

The Maui field in New Zealand currently comprises over 60% of the natural gas produced in New Zealand. Production from the Maui field is expected to decline sharply each year of its remaining life, which has caused significant upward pressure on prices for natural gas in the country. Due to currency exchange increases between the New Zealand dollar and the U.S. dollar, along with increases in our natural gas contract prices, our average natural gas price in New Zealand has increased 34% from the first quarter of 2004 to the fourth quarter of 2005. We expect the prices we receive for our natural gas in New Zealand to continue to improve. During 2006, we anticipate drilling six to eight development wells and expect to drill two to four exploration tests, which includes our Tarata Thrust exploration activity. These New Zealand activities provide us with long-term growth opportunities and significant potential reserves in a country with stable political and economic conditions, existing oil and gas infrastructure, and favorable tax and royalty regimes.

Maintain Financial Flexibility and Disciplined Capital Structure

We practice a disciplined approach to financial management and have historically maintained a disciplined capital structure to provide us with the ability to execute our business plan. As of December 31, 2005, our debt to capitalization was approximately 37%, while our debt to proved reserves ratio was $0.46 per Mcfe, and our debt to PV-10 ratio was 11%. Including our cash on hand at year-end 2005, our net debt to capital ratio would have been 33% and our net debt per Mcfe would be $0.38 per Mcfe. We plan to maintain a capital structure that provides

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financial flexibility through the prudent use of capital, aligning our capital expenditures to our cash flows, and maintaining a strategic hedging program. The combination of hedging with collars, floors, forward sales, and the sale of our New Zealand natural gas production under long-term, fixed-price contracts will provide for a more stable cash flow for the periods covered as described in the Commodity Risk section of this report.

Experienced Technical Team

We employ 50 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 25 years of experience in their technical fields and have been employed by us for an average of over six years. In addition, we engage experienced and qualified consultants to perform various comprehensive seismic acquisitions, processing, reprocessing, interpretation, and other related services. We continually apply our extensive in-house experience and current technologies to benefit our drilling and production operations.

We have increasingly used seismic technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisition, post-stack image enhancement reprocessing, amplitude versus offset datasets, correlation cubes, and detailed formation depletion studies. In 2004, we completed our 3-D seismic survey covering our Lake Washington area and during 2005, all eight of our exploration wells in the Lake Washington area utilized the 3-D seismic data, of which five were successful, and all 24 of our development wells utilized the 3-D seismic data, of which 16 were successful. In 2005, we began a seismic program that encompasses 77 square miles in our Cote Blanche Island area, which is expected to be completed in the third quarter of 2006. In New Zealand, we also plan to acquire seismic on our offshore Kaheru exploration permit in 2006.

We use various recovery techniques, including gas lift, water flooding, and acid treatments to enhance crude oil and natural gas production. We also fracture reservoir rock through the injection of high-pressure fluid, install gravel packs, and insert coiled-tubing velocity strings to enhance and maintain production. We believe that the application of fracturing and coiled-tubing technology has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP Olmos area.

We have developed an expertise in drilling horizontal wells at vertical depths below 10,000 feet, often in a high-pressure environment, involving single or dual lateral legs of several thousand feet. This results in an integrated approach to exploration using multidisciplinary data analysis and interpretation that has helped us identify a number of exploration prospects.

We also employ measurement-while-drilling techniques extensively in our Lake Washington area, which allows us to guide the drill bit during the drilling process. This technology allows the well bore path to be steered parallel to the salt face and to intersect multiple targeted sands in a single well bore.

Operating Areas

The following table sets forth information regarding our proved reserves and production by field:

Area	**Region**	**% of Year-End 2005 Proved Reserves**	**% of 2005 Production**
AWP Olmos	South Texas	23%	13%
Brookeland	Toledo Bend	5%	5%
Lake Washington	South Louisiana	31%	45%
Masters Creek	Toledo Bend	7%	4%
Bay de Chene, Cote Blanche Island	South Louisiana	10%	2%
Rimu/Kauri	New Zealand	11%	14%
TAWN	New Zealand	5%	14%
% of Total		92%	97%

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Domestic Regional Focus Areas

Our domestic regions consist of three main regions located in South Louisiana, South Texas and Toledo Bend, which straddles the Texas and Louisiana border. South Texas is the oldest of our core regions, with our operations being established in the AWP Olmos area in 1989. During 2001, we added Garcia Ranch, an area southeast of AWP Olmos. In mid-1998, we acquired the Masters Creek and Brookeland areas in the Toledo Bend region, with South Bearhead Creek being our most recent acquisition in this region during late 2005. In South Louisiana, we established our operations when we acquired majority interests in producing properties in the Lake Washington field in early 2001, adding Bay de Chene and Cote Blanche Island in December 2004.

South Louisiana

Lake Washington Area. As of December 31, 2005, we owned drilling and production rights in 17,352 net acres in the Lake Washington area located in Plaquemines Parish in South Louisiana, along with lease and seismic options covering another 6,400 acres. Approximately 93% of our proved reserves of 39.8 million BOE in this area at December 31, 2005 were oil and NGLs. To date, we have primarily produced from multiple Miocene sands ranging in depth from greater than 2,000 feet to 10,000 feet. The field is located on a salt dome and has produced over 300 million BOE since its discovery in the 1930s. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and gas from approximately 115 producing wells is gathered from three platforms located in water depths from two to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2005, we drilled 24 development wells and eight exploratory wells, of which 16 development and five exploratory wells were completed. At year-end 2005, we had 87 proved undeveloped locations in this field. Our planned 2006 capital expenditures in this area will focus on drilling at least 26 wells; of these at least three will be exploratory wells with targets derived from recently acquired three-dimensional seismic data. Additional facility work is planned to further improve the deliverability and efficiency in this area.

Bay de Chene and Cote Blanche Island Areas. Bay de Chene is located in Jefferson Parish and Lafourche Parish, while Cote Blanche Island is located in St. Mary Parish, both of which are in South Louisiana in close proximity to Lake Washington. These fields hold predominantly undeveloped reserves. As of December 31, 2005, we owned drilling and production rights in 14,156 net acres in the Bay de Chene field and 7,032 net acres in the Cote Blanche Island field. We plan to spend $40 million to $50 million to begin developing these fields during 2006. These fields were shut-in following the acquisition for facility enhancements and to repair a gas supply line. Beginning in late August of 2005, both fields were shut-in for Hurricanes Katrina and Rita. Bay de Chene field returned to production in the fourth quarter 2005, meanwhile, Cote Blanche Island is expected to resume production late in the first quarter of 2006. At year-end 2005, we had three proved undeveloped locations in the Bay de Chene field and 20 in the Cote Blanche Island field. We drilled our first exploratory well in Bay de Chene in late 2005, which was unsuccessful. During 2006, we plan to drill two to four wells and perform several recompletions in each area. We also have a 3-D seismic acquisition for Cote Blanche Island planned for 2006.

South Texas

AWP Olmos Area. As of December 31, 2005, we owned drilling and production rights in 29,226 net acres in the AWP Olmos Area in South Texas. We have extensive experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 67% natural gas. At year-end 2005, we owned interests in and operated 526 wells in this area producing natural gas from the Olmos sand formation at depths of approximately 9,000 to 11,500 feet. We own nearly 100% of the working interests in all our operated wells.

In 2005, we completed 18 development wells in this area, and performed 23 fracture enhancements. At year-end 2005, we had 118 proved undeveloped locations. Our planned 2006 capital expenditures will focus on drilling 12 to 15 wells in this area.

Garcia Ranch Area. We have been focusing on the deep sands of the Frio formation (10,000 to 16,000 feet) in an area known as Garcia Ranch, which straddles the border of Kenedy County and Willacy County in the southern tip of Texas. Two development wells were drilled in this area in 2005; both were completed.

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Toledo Bend

Brookeland Area. As of December 31, 2005, we owned drilling and production rights in 78,535 net acres and 3,500 fee mineral acres in the Brookeland area. This area is located in East Texas near the border of Louisiana in Jasper and Newton counties. We primarily drill horizontal wells and produce from the Austin Chalk formation in this area. The reserves are approximately 57% oil and natural gas liquids. During 2005, we participated in drilling one non-operated development well, which was successful. At year-end 2005, we had 11 proved undeveloped locations. Our planned 2006 capital expenditures in Toledo Bend region include drilling one to two development wells.

Masters Creek Area. As of December 31, 2005, we owned drilling and production rights in 46,635 net acres and 91,994 fee mineral acres in the Masters Creek area. This area is located in Central Louisiana near the Texas-Louisiana border in the two parishes of Vernon and Rapides. It contains horizontal wells producing both oil and gas from the Austin Chalk formation. The reserves are approximately 68% oil and NGLs. At year-end 2005, we had eight proved undeveloped locations.

South Bearhead Creek Area. In November and December 2005, we acquired interests in the South Bearhead Creek field, which is located in the Toledo Bend region approximately 50 miles south of our Masters Creek field and 30 miles north of Lake Charles, Louisiana. Oil and gas are produced in this area predominantly from the upper and lower Wilcox sands, at depths ranging from approximately 10,600 to 13,700 feet. The field also has production in the Cockfield sands at approximately 8,000 to 8,500 feet. South Bearhead Creek field was discovered in 1958 by a major oil company. It is a large east-west trending anticlinal closure and has had cumulative production of over 4 million BOE.

As of December 31, 2005, we owned drilling and production rights in 5,258 net acres in the South Bearhead Creek area. At year-end 2005, we had 19 proved undeveloped locations in this field. Our 2006 plans for this area include two to four development wells and several recompletions.

New Zealand Regional Focus Area

Our New Zealand region contains two anchor assets, the Rimu/Kauri area and the TAWN area. Our activity in New Zealand began in 1995. As of December 31, 2005, our exploration permit 38719, which we operate, included approximately 64,061 acres in the Taranaki Basin of New Zealand s north island. In April 2004, two other permits (38756 and 38759) within the Taranaki Basin were consolidated with our permit 38719 to form one permit area. This acreage includes our Rimu/Kauri area, and our Rimu and Kauri mining permit areas. Our 2006 planned activity in New Zealand includes drilling six to eight development wells and two to four exploration wells. We also plan to acquire seismic on our offshore Kaheru exploration permit in 2006.

Rimu/Kauri Area. Since 2002, we have held a 100% working interest in petroleum mining permit 38151 covering approximately 5,500 acres in the Rimu area for a primary term of 30 years. We began commercial production from the Rimu area in May 2002, and own a hydrocarbon-processing facility in this area as well. During 2005, we completed two out of five wells in the Kauri area. One of these wells successfully targeted the Kauri sands, and one was completed in the Manutahi sand. We were awarded a 30-year primary term mining permit covering approximately 8,714 acres in the Kauri area in April 2005. Our natural gas production from this area is sold to Genesis Power Ltd. under a long-term contract for use at its Huntly Power Station, New Zealand s largest thermal power station.

TAWN Area. Our interest in TAWN consists of a 100% working interest in four petroleum mining permits, 38138 through 38141, covering producing oil and gas fields and extensive associated hydrocarbon-processing facilities and pipelines. The properties are collectively identified as the TAWN properties, an acronym derived from the first letters of the field names the Tariki field, the Ahuroa field, the Waihapa field, and the Ngaere field. The four fields include 18 wells where the purchaser of gas is Contact Energy. In 2005, we completed the Piakau North A1 exploration well in this area. The TAWN assets are located approximately 17 miles north of the Rimu/Kauri area.

Our infrastructure in New Zealand includes two hydrocarbon-processing plants with significant excess capacity. We also own the pipelines connecting the fields and facilities to export terminals and interior markets.

Diversity Areas. Two prospects, which were drilling at the end of 2005, are located in our TAWN area and are identified as the Goss prospect (Goss A1 well), and the Trapper prospect (Trapper A1 well). Both prospects have the Kapuni group sands (the major reservoir in the basin) as their main target, but as these wells are drilled they will also pass through the Tariki sandstone and other major producing sands in the basin. We have entered into a series of farm-out agreements with Mighty River Power (MRP), a state owned New Zealand utility, which provide for a 50% working interest in both the Goss A1 well, and the Trapper A1 well. Under the farm-out agreements, MRP will provide the funding for the drilling of these exploration wells and can earn a 50% working interest in certain commercial discoveries, outside of known productive zones, resulting from these wells. Once MRP has earned its 50%, we will equally share any future development costs subject to the terms of the agreements. We will continue to maintain our 100% working interest in the existing producing horizons and facilities in both the TAWN and Rimu/Kauri areas.

In December 2004, we entered into a farm-in agreement with Ballance Agri-Nutrients Limited of New Zealand for their exploration permit 38742. The approximately 16,800 gross acre permit is located onshore in the north-central Taranaki Basin. Under the terms of the contract, we became the operator of the permit, and now have an 80% working interest. We anticipate drilling an exploratory well in this area in the second half of 2006.

Summary of New Zealand Government Licenses and Permits

Our acreage in New Zealand is licensed from the New Zealand government under both production exploration permits (PEP), production mining licenses (PML), and production mining permits (PMP). These licenses and permits as of December 31, 2005 are summarized in the following table:

Permit	Date of Initial Interest Acquired	Swift s Interest
PEP 38495	2005	50%
PEP 38716	1999	21%
PEP 38719	1996	100%
PEP 38742	2004	80%
PML 38138	2002	100%
PML 38139	2002	100%
PML 38140	2002	100%
PML 38141	2002	100%
PMP 38151	2002	100%
PMP 38155	2005	100%

Details of these licenses can be found on the New Zealand government s Crown Minerals website at http://crownminerals.med.govt.nz/index.asp.

Oil and Natural Gas Reserves

The following tables present information regarding proved reserves of oil and natural gas attributable to our interests in producing properties as of December 31, 2005, 2004, and 2003. The information set forth in the tables regarding reserves is based on proved reserves reports prepared by us and audited by H. J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers. Gruy has audited 100% of our proved reserves. Gruy s audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy s audit was based upon review of all available production histories and other geological, economic, and engineering data, all of which was provided by us.

Estimates of future net revenues from our proved reserves and their PV-10 Value are made using oil and gas sales prices in effect as of the dates of such estimates adjusted for the effects of hedging and are held constant, for that year s reserves calculation, throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. We have interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as

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proved and are not reflected in the following tables. Our hedges at year-end 2005 consisted of natural gas price floors with strike prices lower than the period-end price and thus did not materially affect prices used in these calculations. The weighted averages of such year-end 2005 prices domestically were $10.36 per Mcf of natural gas, $60.00 per barrel of oil, and $33.28 per barrel of NGL, compared to $5.87, $42.21, and $26.49 at year-end 2004 and $5.53, $30.88, and $21.81 at year-end 2003, respectively. The weighted averages of such year-end 2005 prices for New Zealand were $3.79 per Mcf of natural gas, $60.98 per barrel of oil, and $19.20 per barrel of NGL, compared to $3.07, $33.60, and $20.48 in 2004 and $2.04, $26.78, and $14.10 in 2003, respectively. The weighted averages of such year-end 2005 prices for all our reserves, both domestically and in New Zealand, were $8.94 per Mcf of natural gas, $60.12 per barrel of oil, and $31.40 per barrel of NGL, compared to $5.16 $41.07, and $25.48 in 2004 and $4.56, $30.16, and $20.61 in 2003, respectively.

The following tables set forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the Securities and Exchange Commission and their PV-10 Value as of December 31, 2005, 2004, and 2003. Operating costs, development costs, asset retirement obligation costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in supplemental information to our consolidated financial statements, which is calculated after provision for future income taxes. We combine NGLs with oil for reserves reporting purposes. PV-10 is a non-GAAP measure, see the reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure, in the section below this table.

	As of December 31, 2005		
	Total	**Domestic**	**New Zealand**
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	152,001	125,368	26,633
Proved undeveloped	135,472	99,907	35,565
Total	287,473	225,275	62,198
Oil reserves (MBbl):			
Proved developed	37,990	35,298	2,691
Proved undeveloped	41,063	34,485	6,579
Total	79,053	69,783	9,270
Total Estimated Reserves (Bcfe)	762	644	118
Estimated Discounted Present Value of Proved Reserves (In millions)			
Proved developed	$ 1,721	$ 1,612	$ 109
Proved undeveloped	1,450	1,248	202
PV-10 Value	$ 3,171	$ 2,860	$ 311

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	As of December 31, 2004		
	Total	Domestic	New Zealand
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	193,311	140,549	52,762
Proved undeveloped	124,935	97,343	27,593
Total	318,246	237,892	80,355
Oil reserves (MBbl):			
Proved developed	42,038	36,629	5,409
Proved undeveloped	38,229	32,510	5,719
Total	80,267	69,139	11,128
Total Estimated Reserves (Bcfe)	800	653	147
Estimated Discounted Present Value of Proved Reserves (In millions)			
Proved developed	$ 1,182	$ 1,038	$ 144
Proved undeveloped	839	760	79
PV-10 Value	$ 2,021	$ 1,797	$ 224

	As of December 31, 2003		
	Total	Domestic	New Zealand
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	210,120	138,173	71,947
Proved undeveloped	125,685	104,148	21,537
Total	335,805	242,321	93,484
Oil reserves (MBbl):			
Proved developed	45,525	38,768	6,757
Proved undeveloped	35,235	28,248	6,987
Total	80,760	67,016	13,744
Total Estimated Reserves (Bcfe)	820	644	176
Estimated Discounted Present Value of Proved Reserves (In millions)			

Proved developed	$ 941	$ 806	$ 135
Proved undeveloped	598	517	80
PV-10 Value	$ 1,539	$ 1,323	$ 215

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserves reports of other engineers might differ from the reports contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Future prices received for the sale of oil and gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. There can be no assurance that these estimates are accurate predictions of the present value of future net cash flows from oil and gas reserves.

No other reports on our reserves have been required to be filed, nor have any been filed with any federal agency.

The closest GAAP measure to PV-10, a non-GAAP measure, is the standardized measure of discounted future net cash flows. We believe PV-10 is a helpful measure in evaluating the value of our oil and gas reserves and many securities analysts and investors use PV-10. We use PV-10 in our ceiling test computations, and we also compare PV-10 against our debt balances. The following table is a reconciliation between PV-10 and the standardized measure of discounted future net cash flows:

	As of December 31, 2005		
(In millions)	**Total**	**Domestic**	**New Zealand**
PV-10 Value	$ 3,171	$ 2,860	$ 311
Future income taxes (discounted at 10%)	(984)	(942)	(42)
Asset retirement obligations (discounted at 10%)	(27)	(23)	(4)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 2,159	$ 1,895	$ 265

	As of December 31, 2004		
(In millions)	**Total**	**Domestic**	**New Zealand**
PV-10 Value	$ 2,021	$ 1,797	$ 224
Future income taxes (discounted at 10%)	(533)	(521)	(12)
Asset retirement obligations (discounted at 10%)	(23)	(19)	(4)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 1,465	$ 1,257	$ 208

	As of December 31, 2003		
(In millions)	**Total**	**Domestic**	**New Zealand**
PV-10 Value	$ 1,539	$ 1,323	$ 215
Future income taxes (discounted at 10%)	(392)	(351)	(41)
Asset retirement obligations (discounted at 10%)	(13)	(9)	(2)
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 1,135	$ 963	$ 172

Proved Undeveloped Reserves

The following table sets forth the aging and PV-10 value of our proved undeveloped reserves as of December 31, 2005:

Year Added	**Volume (Bcfe)**	**% of PUD Volumes**	**PV-10 Value (in millions)**	**% of PUD PV-10 Value**
2005	102.9	27%	$ 439.2	30%
2004	70.4	18%	299.4	21%
2003	59.4	16%	248.7	17%
2002	40.6	11%	122.6	8%
2001	16.5	4%	74.8	5%
Prior to 2001	92.1	24%	264.0	19%
Total	381.9	100%	$ 1,448.7	100%

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Sensitivity of Reserves to Pricing

As of December 31, 2005, a 5% increase in crude oil and NGL pricing would increase our total estimated proved reserves of 761.8 Bcfe by approximately 0.3 Bcfe, and increase the total PV-10 Value of $3.2 billion by approximately $129 million. Similarly, a 5% decrease in crude oil and NGL pricing would decrease our total estimated proved reserves by approximately 0.2 Bcfe and decrease the total PV-10 Value by approximately $131 million.

As of December 31, 2005 a 5% increase in natural gas pricing (exclusive of fixed contract volumes) would increase our total estimated proved reserves by approximately 0.4 Bcfe and increase the total PV-10 Value by approximately $60 million. Similarly, a 5% decrease in natural gas pricing (exclusive of fixed contract volumes) would decrease our total estimated proved reserves by approximately 0.3 Bcfe and decrease the total PV-10 Value by approximately $63 million.

Oil and Gas Wells

The following table sets forth the gross and net wells in which we owned an interest at the following dates:

	Oil Wells	Gas Wells	Total Wells(1)
December 31, 2005:			
Gross	402	565	967
Net	324.84	497.47	822.31
December 31, 2004:			
Gross	358	574	932
Net	308.8	525.9	834.7
December 31, 2003:			
Gross	397	560	957
Net	340.6	504.0	844.6

(1) Excludes 49 service wells in 2005, 40 service wells in 2004, and 41 service wells in 2003.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2005:

	Developed(1)		Undeveloped(1)	
	Gross	Net	Gross	Net
Alabama	9,045.27	2,587.86	124.22	79.82
Louisiana	104,746.41	86,175.61	20,019.57	15,656.27
Texas	134,942.31	93,034.91	21,507.04	15,100.67
Wyoming	640.00	151.06	54,117.93	52,322.47
All other states	320.00	266.66	400.00	319.82
Offshore Louisiana	4,609.37	276.56	5,000.00	258.34
Offshore Texas	2,880.00	74.39		
Total Domestic	257,183.36	182,567.05	101,168.76	83,737.39
New Zealand	9,480.00	9,118.15	143,250.85	114,291.18
Total	266,663.36	191,685.20	244,419.61	198,028.57

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(1) Fee mineral acres acquired in the Brookeland and Masters Creek areas acquisition are not included in the above leasehold acreage table. We have 26,345 developed fee mineral acres and 69,149 undeveloped fee mineral acres for a total of 95,494 fee mineral acres.

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2005:

		Gross Wells			Net Wells		
Year	**Type of Well**	**Total**	**Producing**	**Dry**	**Total**	**Producing**	**Dry**
2005	Exploratory Domestic	9	5	4	9.0	5.0	4.0
	Development Domestic	45	37	8	44.3	36.3	8.0
	Exploratory New Zealand	5	1	4	3.7	1.0	2.7
	Development New Zealand	5	2	3	5.0	2.0	3.0
2004	Exploratory Domestic	10	4	6	7.5	2.3	5.2
	Development Domestic	44	37	7	41.7	35.0	6.7
	Exploratory New Zealand	1		1	1.0		1.0
	Development New Zealand	11	10	1	11.0	10.0	1.0
2003	Exploratory Domestic	8	5	3	7.3	5.0	2.3
	Development Domestic	63	53	10	61.9	51.9	10.0
	Exploratory New Zealand	1		1	0.5		0.5
	Development New Zealand	3	3		3.0	3.0	

Operations

We generally seek to be operator in the wells in which we have a significant economic interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors supervised by us provide this equipment and personnel. We employ drilling, production, and reservoir engineers, geologists, and other specialists who work to improve production rates, increase reserves, and lower the cost of operating our oil and gas properties.

Oil and gas properties are customarily operated under the terms of a joint operating agreement. These agreements usually provide for reimbursement of the operator s direct expenses and for payment of monthly per-well supervision fees. Supervision fees vary widely depending on the geographic location and depth of the well and whether the well produces oil or natural gas. The fees for these activities in 2005 totaled $7.8 million and ranged from $529 to $2,231 per well per month.

Marketing of Production

Domestically, we typically sell our oil and natural gas production at market prices near the wellhead or at a central point after gathering and/or processing. We usually sell our natural gas in the spot market on a monthly basis, while we sell our oil at prevailing market prices. We do not refine any oil we produce. Shell Oil Company and its affiliates, both domestically and in New Zealand, accounted for 10% or more of our total revenues during the years ended

December 31, 2005 and 2004, with purchases accounting for approximately 42% and 48% of our total oil and gas sales, respectively. However, due to the demand for oil and gas and availability of other purchasers, we do not believe that the loss of any single oil or gas purchaser or contract would materially affect our revenues.

Our oil production from the Lake Washington area is delivered into ExxonMobil s crude oil pipeline system or transported on barges for sales to various purchasers at prevailing market prices or at fixed prices tied to the then current NYMEX crude oil contract for the applicable month(s). Our natural gas production from this area is either consumed on the lease or is delivered into El Paso s Tennessee Gas Pipeline system and then sold in the spot market at prevailing prices.

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In 1998, we entered into gas processing and gas transportation agreements for our natural gas production in the AWP Olmos area with PG&E Energy Trading Corporation, which was assumed in December 2000 by El Paso Hydrocarbon, LP, and El Paso Industrial, LP, and then assumed by Enterprise Hydrocarbons L.P. in September 2004, for up to 75,000 Mcf per day, which provided for a ten-year term with automatic one-year extensions unless terminated earlier. We believe that these arrangements adequately provide for our gas transportation and processing needs in the AWP Olmos area for the foreseeable future.

Our oil production from the Brookeland and Masters Creek areas is sold to various purchasers at prevailing market prices. Our natural gas production from these areas is processed under long term gas processing contracts with Duke Energy Field Services, Inc. The processed liquids and residue gas production are sold in the spot market at prevailing prices.

Through 2005, our oil production in New Zealand was sold to Shell Petroleum Mining, and now is sold to BP at international prices tied to the Asia Petroleum Price Index (APPI) Tapis posting, less the cost of storage, trucking, and transportation.

Our natural gas production from our TAWN fields is sold under a long-term fixed price contract with Contact Energy. Our natural gas production from the Rimu field is sold to Genesis Power Ltd. under a long-term fixed price contract that was modified in 2003 and covers approximately 7.2 Bcfe per year for a three-year period. During 2005, additional production volumes from our fields, over the contract maximum, were sold to Contact Energy or Genesis Power Ltd. at prevailing market rates.

Production of NGLs in New Zealand is sold to Rockgas Ltd. under long-term contracts tied to New Zealand s domestic natural gas liquids market.

The following table summarizes sales volumes, sales prices, and production cost information for our net oil and natural gas production for the three-year period ended December 31, 2005:

	Year Ended December 31,		
	2005	**2004**	**2003**
Net Sales Volume:			
Oil (MBbls)(1)	5,159	4,722	3,369
Natural Gas Liquids (MBbls)(2)	838	1,040	823
Natural gas (MMcf)(3)	23,609	23,742	28,003
Total (MMcfe)	59,590	58,319	53,158
Average Sales Price:			
Oil (Per Bbl)(1)	$ 53.63	$ 40.24	$ 29.89
Natural Gas Liquids (Per Bbl)(2).	$ 28.04	$ 22.52	$ 17.60
Natural gas (Per Mcf)(3)	$ 5.23	$ 4.12	$ 3.42
Average Production Cost (Per Mcfe)	$ 1.50	$ 1.23	$ 0.99

(1) Oil production for 2005, 2004, and 2003 includes New Zealand production of 449,994 barrels at an average price per barrel of $55.57, 452,753 barrels at an average price per barrel of $42.15, and 572,683 barrels at an average price per barrel of $29.58, respectively.

(2) Natural gas liquids production for 2005, 2004 and 2003 includes New Zealand production of 329,377 barrels at an average price of $18.84 per barrel, 350,303 barrels with an average price of $17.96 per barrel, and 283,227 barrels with an average price of $13.50 per barrel.

(3) Natural gas production for 2005, 2004 and 2003 includes New Zealand production of 11,869,757 Mcf with an average price of $3.09 per Mcf, 11,441,954 Mcf with an average price of $2.38 per Mcf, and 14,258,679 Mcf with an average price of $1.83 per Mcf.

Risk Management

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including blowouts, cratering, pipe failure, casing collapse, fires, and adverse weather conditions, each of which could result in severe damage to or destruction of oil and gas wells, production facilities or other property, or individual injuries. The oil and gas exploration business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharges of toxic substances or gases that could expose us to substantial liability due to pollution and other environmental damage. See 1A. Risk Factors of this report for more details and for discussion of other risks. We maintain comprehensive insurance coverage, including general liability insurance, officer and director liability insurance, and property damage insurance. Prior to and at the time of Hurricanes Katrina and Rita, we maintained business interruption insurance as well. Since such time, the cost of such insurance coverage increased to a level that we believe makes it uneconomical to maintain at this time. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but if a significant accident, or other event occurs that is uninsured or not fully covered by insurance, it could adversely affect us.

Commodity Risk

The oil and gas industry is affected by the volatility of commodity prices. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. At December 31, 2005, we had price floors in place through the June 2006 contract month for natural gas; these cover a portion of our domestic natural gas production for February 2006 to June 2006. The natural gas price floors cover notional volumes of 2,075,000 MMBtu, with a weighted average floor price of $8.39 per MMBtu. Our natural gas price floors in place at December 31, 2005 are expected to cover approximately 35% to 40% of our domestic natural gas production from February 2006 to June 2006.

Competition

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and gas properties, as well as for equipment, labor, and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition. Our ability to replace and expand our reserves base depends on our continued ability to attract and retain quality personnel and identify and acquire suitable producing properties and prospects for future drilling.

Regulations

Environmental Regulations

Our domestic exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit by operators before drilling commences, prohibit drilling activities on certain lands lying within wilderness areas, wetlands, and other ecologically sensitive and protected areas, and impose substantial remedial liabilities for pollution resulting from drilling operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of significant investigatory or remedial obligations, and the imposition of injunctive relief that limits or prohibits our operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in substantial compliance with current environmental laws and regulations and have not experienced any material adverse effect from such compliance, there is no assurance that this trend will continue in the future.

We currently own or lease, and have in the past owned or leased, numerous properties in connection with our domestic operations that have been used for the exploration and production of oil and gas for many years. Although

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we have used operation and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or other wastes may have been disposed or released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, the federal Resource Conservation and Recovery Act or RCRA, the federal Clean Water Act, the federal Clean Air Act, the federal Oil Pollution Act or OPA, and analogous state laws. Under such laws and any implementing regulations, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury or property damages allegedly caused by the release of petroleum hydrocarbons or other wastes into the environment.

Our domestic operations offshore in the Gulf of Mexico are subject to OPA, which imposes a variety of requirements related to the prevention of oil spills, and liability for damages resulting from such spills in United States waters. The OPA imposes strict, joint and several liability on responsible parties for oil removal costs and a variety of public and private damages, including natural resource damages. Liability limits for offshore facilities require a responsible party to pay all removal costs, plus up to $75 million in other damages. These liability limits do not apply, however, if the spill was caused by gross negligence or willful misconduct of the party, if the spill resulted from violation of a federal safety, construction or operation regulation, or if the party fails to report the spill or cooperate fully in any resulting cleanup. The OPA also requires a responsible party at an offshore facility to submit proof of its financial ability to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We believe our operations are in substantial compliance with OPA requirements.

Our operations in New Zealand could also potentially be subject to similar foreign governmental controls and restrictions pertaining to protection of human health and the environment. These controls and restrictions may include the need to acquire permits, prohibitions on drilling in certain environmentally sensitive areas, performance of investigatory or remedial actions for any releases of petroleum hydrocarbons or other wastes caused by us or prior operators, closure and restoration of facility sites, and payment of penalties for violations of applicable laws and regulations. While we believe that we are in substantial compliance with current environmental laws and regulations in New Zealand, and have not experienced any material adverse effect from such compliance, there is no assurance that this trend will continue in the future.

United States Federal, State and New Zealand Regulation of Oil and Natural Gas

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the federal government and are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The Federal Energy Regulatory Commission (FERC) is continually proposing and implementing new rules and regulations affecting the natural gas industry, most notably interstate natural gas transmission companies that remain subject to the FERC s jurisdiction. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. Some recent FERC proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines.

Our sales of crude oil, condensate and NGLs are not currently subject to FERC regulation. However, the ability to transport and sell such products is dependent on certain pipelines whose rates, terms and conditions of service are subject to FERC regulation.

Production of any oil and gas by us will be affected to some degree by state regulations. Many states in which we operate have statutory provisions regulating the production and sale of oil and gas, including provisions regarding deliverability. Such statutes, and the regulations promulgated in connection therewith, are generally intended to prevent waste of oil and gas and to protect correlative rights to produce oil and gas between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and gas produced by assigning allowable rates of production to each well or proration unit, which could restrict the rate of production below the

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rate that a well would otherwise produce in the absence of such regulation. In addition, certain state regulatory authorities can limit the number of wells or the locations where wells may be drilled. Any of these actions could negatively affect the amount or timing of revenues. Likewise, the government of New Zealand regulates the exploration, production, sales, and transportation of oil and natural gas.

Federal Leases

Some of our domestic properties are located on federal oil and gas leases administered by various federal agencies, including the Bureau of Land Management. Various regulations and administrative orders affect the terms of leases, and in turn may affect our exploration and development plans, methods of operation, and related matters.

Litigation

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and gas wells. In our opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

Employees

At December 31, 2005, we employed 311 persons. Of these employees, 75 were in New Zealand, including four expatriate employees. Eight of our New Zealand employees are members of a union. None of our other employees are represented by a union. Relations with employees are considered to be good.

Facilities

At December 31, 2005, we occupied approximately 120,000 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten-year lease expiring in 2015. The lease requires payments of approximately $216,000 per month. In New Zealand we leased approximately 18,400 square feet of office space, under leases expiring in 2008 and 2009. These New Zealand leases require payments of approximately $33,000 per month. We also have field offices in various locations from which our employees supervise local oil and gas operations.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, amendments to those reports, changes in and stock ownership of our directors and executive officers, together with other documents filed with the Securities and Exchange Commission under the Securities Exchange Act can be accessed free of charge on our web site at www.swiftenergy.com as soon as reasonably practicable after we electronically file these reports with the SEC. All exhibits and supplemental schedules to these reports are available free of charge through the SEC web site at www.sec.gov. In addition, we have adopted a Code of Ethics for Senior Financial Officers and Principal Executive Officer. We have posted this Code of Ethics on our website, where we also intend to post any waivers from or amendments to this Code of Ethics.

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Item 1A. Risk Factors

The nature of the business activities conducted by Swift Energy subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are described in Items 1 and 2 Business and Properties Competition and Regulations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Our oil and gas exploration and production business involves high risks and we may suffer uninsured losses.

These risks include blowouts, explosions, adverse weather effects and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Increased hurricane activity over the past two years has resulted in production curtailments and physical damage to the Company s Gulf Coast operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of these risks, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Oil and natural gas prices are volatile. A substantial decrease in oil and natural gas prices would adversely affect our financial results.

Our future revenues, net income, cash flow, and the value of our oil and natural gas properties depend primarily upon market prices for oil and natural gas. Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. The recent record high oil and natural gas prices may not continue and could drop precipitously in a short period of time. The prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, worldwide economic conditions, weather conditions, currency exchange rates, and political conditions in major oil producing regions, especially the Middle East. A significant decrease in price levels for an extended period would negatively affect us in several ways:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to increase production or replace reserves;
- certain reserves would no longer be economic to produce, leading to both lower cash flow and proved reserves;
- our lenders could reduce the borrowing base under our bank credit facility because of lower oil and natural gas reserves values, reducing our liquidity and possibly requiring mandatory loan repayments; and
- access to other sources of capital, such as equity or long term debt markets, could be severely limited or unavailable in a low price environment.

Consequently, our revenues and profitability would suffer.

Our level of debt could reduce our financial flexibility, and we currently have the ability to incur substantially more debt, including secured debt.

As of December 31, 2005, our total debt comprised approximately 37% of our total capitalization. Although our bank credit facility and indentures limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness, we will be permitted to incur significant additional indebtedness, including secured indebtedness, in the future if specified conditions are satisfied. All borrowings under our bank credit facility are effectively senior to our outstanding 7-5/8% senior notes and 9-3/8% senior subordinated notes to the extent of the value of the collateral securing those borrowings. Our current level of indebtedness:

- will require us to dedicate a substantial portion of our cash flow to the payment of interest;
- will subject us to a higher financial risk in an economic downturn due to substantial debt service costs;

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may limit our ability to obtain financing or raise equity capital in the future; and

may place us at a competitive disadvantage to the extent that we are more highly leveraged than some of our peers.

Higher levels of indebtedness would increase these risks.

Estimates of proved reserves are uncertain, and revenues from production may vary significantly from expectations.

The quantities and values of our proved reserves included in this report are only estimates and subject to numerous uncertainties. Estimates by other engineers might differ materially. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation. These estimates depend on assumptions regarding quantities and production rates of recoverable oil and natural gas reserves, future prices for oil and natural gas, timing and amounts of development expenditures and operating expenses, all of which will vary from those assumed in our estimates. These variances may be significant.

Any significant variance from the assumptions used could result in the actual amounts of oil and natural gas ultimately recovered and future net cash flows being materially different from the estimates in our reserves reports. In addition, results of drilling, testing, production, and changes in prices after the date of the estimates of our reserves may result in substantial downward revisions. These estimates may not accurately predict the present value of net cash flows from our oil and natural gas reserves.

At December 31, 2005, approximately 50% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserves data assumes that we can and will make these expenditures and conduct these operations successfully, which may not occur.

If we cannot replace our reserves, our revenues and financial condition will suffer.

Unless we successfully replace our reserves, our long- term production will decline, which could result in lower revenues and cash flow. When oil and natural gas prices decrease, our cash flow decreases, resulting in less available cash to drill and replace our reserves and an increased need to draw on our bank credit facility. Even if we have the capital to drill, unsuccessful wells can hurt our efforts to replace reserves. Additionally, lower oil and natural gas prices can have the effect of lowering our reserves estimates and the number of economically viable prospects that we have to drill.

Drilling wells is speculative and capital intensive.

Developing and exploring properties for oil and natural gas requires significant capital expenditures and involves a high degree of financial risk, including the risk that no commercially productive oil or gas reservoirs will be encountered. The budgeted costs of drilling, completing, and operating wells are often exceeded and can increase significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages, and mechanical difficulties. Moreover, the successful drilling or completion of an oil or gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

Hurricanes or tropical storms;

environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas, or other pollution into the environment, including groundwater and shoreline contamination;

- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our financial condition.

We are exposed to the risk of fluctuations in foreign currencies, primarily the New Zealand dollar.

Fluctuations in rates between the New Zealand dollar and U.S. dollar impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, and natural gas and NGL sales contracts denominated in New Zealand dollars. We do not hedge against the risks associated with fluctuations in exchange rates. Although we may use hedging techniques in the future, we may not be able to eliminate or reduce the effects of currency fluctuations. As a result, exchange rate fluctuations could have an adverse impact on our operating results.

We have incurred a write-down of the carrying values of our properties in the past and could incur additional write-downs in the future.

Under the full cost method of accounting, SEC accounting rules require that on a quarterly basis we review the carrying value of our oil and gas properties on a country-by-country basis for possible write-down or impairment. Under these rules, capitalized costs of proved reserves may not exceed a ceiling calculated at the present value of estimated future net revenues from those proved reserves, determined using a 10% per year discount and unescalated prices in effect as of the end of each fiscal quarter. Capital costs in excess of the ceiling must be permanently written down.

We recorded an after-tax, non-cash charge during the fourth quarter of 2001 of $63.5 million. This write-down resulted in a charge to earnings and a reduction of stockholders equity, but did not impact our cash flow from operating activities. If commodity prices decline or if we have significant downward reserves revisions, we could incur additional write-downs in the future.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Reserves on acquired properties may not meet our expectations, and we may be unable to identify liabilities associated with acquired properties or obtain protection from sellers against associated liabilities.

Property acquisition decisions are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately a property s production and profitability. In addition, we may have difficulty integrating future acquisitions into our operations, and they may not achieve our desired profitability objectives. Likewise, as is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except through the transferor. In many instances, title opinions are not obtained if, in our judgment, it would

be uneconomical or impractical to do so. Losses may result from title defects or from defects in the assignment of leasehold rights. While our current operations are primarily in Louisiana, Texas, and New Zealand, we may pursue acquisitions of properties located in other geographic areas, which would decrease our geographical concentration, and could also be in areas in which we have no or limited experience.

In addition, our assessment of acquired properties may not reveal all existing or potential problems or liabilities, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of acquired properties in addition to the risk that the properties may not perform in accordance with our expectations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities, if at all, to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects. In addition, a variety of factors, including geological and market-related, can cause a well to become uneconomical or only marginally economical. For example, if oil and natural gas prices are much lower after we complete a well than when we identified it as a prospect, the completed well may not yield commercially viable quantities.

In many instances, title opinions on our oil and gas acreage are not be obtained if in our judgment it would be uneconomical or impractical to do so.

As is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except as to claims made by, through, or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and expose us to risk of financial loss.

We enter into hedging transactions for our oil and natural gas production to reduce exposure to fluctuations in the price of oil and natural gas, primarily to protect against declines in prices. Our hedges at year-end 2005 consisted of mainly natural gas price floors with strike prices lower than the period end prices. Our hedging transactions have also consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions as well as crude oil price floors. We intend to continue to enter into these types of hedging transactions in the foreseeable future. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions other than floors may limit the benefit we would have otherwise received from increases in the price for oil and natural gas. Additionally, hedging transactions other than floors may expose us to cash margin requirements.

We may have difficulty competing for oil and gas properties or supplies.

We operate in a highly competitive environment, competing with major integrated and independent energy companies for desirable oil and gas properties, as well as for the equipment, labor, and materials required to develop and operate such properties. Many of these competitors have financial and technological resources substantially greater than ours. The market for oil and gas properties is highly competitive and we may lack technological information or expertise available to other bidders. We may incur higher costs or be unable to acquire and develop desirable properties at costs we consider reasonable because of this competition.

Our business depends on oil and natural gas transportation facilities, some of which are owned by others.

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The marketability of our oil and natural gas production depends in part on the availability, proximity, and capacity of pipeline systems owned by third parties. The unavailability of or lack of available capacity on these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Although we have some contractual control over the transportation of our product, material changes in these business relationships could materially affect our operations. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Governmental laws and regulations are costly and stringent, especially those relating to environmental protection.

Our domestic exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in our efforts to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operations. Changes in or additions to environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could have a material adverse effect our operations and financial position.

Our operations outside of the United States could also be subject to similar foreign governmental controls and restrictions pertaining to protection of human health and the environment. These controls and restrictions may include the need to acquire permits, prohibitions on drilling in certain environmentally sensitive areas, performance of investigatory or remedial actions for any releases of petroleum hydrocarbons or other wastes caused by us or prior owners or operators, closure, and restoration of facility sites, and payment of penalties for violations of applicable laws and regulations.

Item 1B. Unresolved Staff Comments

None.

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Glossary of Abbreviations and Terms

The following abbreviations and terms have the indicated meanings when used in this report:

Bbl Barrel or barrels of oil.

Bcf Billion cubic feet of natural gas.

Bcfe Billion cubic feet of natural gas equivalent (see Mcfe).

BOE Barrels of oil equivalent.

Development Well A well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

Discovery Cost With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred exploration and development costs (exclusive of future development costs) by net reserves added during the period through extensions, discoveries, and other additions.

Dry Well An exploratory or development well that is not a producing well.

EBITDA Earnings before interest, taxes, depreciation, depletion and amortization.

EBITDAX Earnings before interest, taxes, depreciation, depletion and amortization, and exploration expenses. Since Swift uses full-cost accounting for oil and property expenditures, as noted in footnote one of the accompanying consolidated financial statements, exploration expenses are not applicable to Swift.

Exploratory Well A well drilled either in search of a new, as yet undiscovered oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir.

FASB The Financial Accounting Standards Board.

Gigajoules A unit of energy equivalent to .95 Mcf of 1,000 Btu of natural gas.

Gross Acre An acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

Gross Well A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

MBbl Thousand barrels of oil.

Mcf Thousand cubic feet of natural gas.

Mcfe Thousand cubic feet of natural gas equivalent, which is determined using the ratio of one barrel of oil, condensate, or natural gas liquids to 6 Mcf of natural gas.

MMBbl Million barrels of oil.

MMBtu Million British thermal units, which is a heating equivalent measure for natural gas and is an alternate measure of natural gas reserves, as opposed to Mcf, which is strictly a measure of natural gas volumes. Typically, prices quoted for natural gas are designated as price per MMBtu, the same basis on which natural gas is contracted for sale.

MMcf Million cubic feet of natural gas.

MMcfe Million cubic feet of natural gas equivalent (see Mcfe).

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Net Acre A net acre is deemed to exist when the sum of fractional working interests owned in gross acres equals one. The number of net acres is the sum of fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Net Well A net well is deemed to exist when the sum of fractional working interests owned in gross wells equals one. The number of net wells is the sum of fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

NGL Natural gas liquid.

Producing Well An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

* **Proved Developed Oil and Gas Reserves** Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

* **Proved Oil and Gas Reserves** The estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.

* **Proved Undeveloped Oil and Gas Reserves** Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Proved Undeveloped (PUD) Locations A location containing proved undeveloped reserves.

PV-10 Value The estimated future net revenues to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

Reserves Replacement Cost With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred acquisition, exploration, and development costs (exclusive of future development costs) by net reserves added during the period.

SFAS Statement of Financial Accounting Standards.

TAWN New Zealand producing properties acquired by Swift in January 2002. TAWN is comprised of the Tariki, Ahuroa, Waihapa, and Ngaere fields.

* These definitions regarding various types of proved reserves are only abbreviated versions of the Securities and Exchange Commission s definitions of these terms contained in Rule 4-10(a) of Regulation S-X. See www.sec.gov/divisions/corpfin/forms/regsx.htm#gas for the full text of the SEC s definitions of these terms.

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Item 3. Legal Proceedings

No material legal proceedings are pending other than ordinary, routine litigation and claims incidental to our business.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted during the fourth quarter of 2005 to a vote of security holders.

PART II

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

Common Stock, 2004 and 2005

Our common stock is traded on the New York Stock Exchange and the Pacific Exchange, Inc., under the symbol SFY. The high and low quarterly sales prices for the common stock for 2004 and 2005 were as follows :

	2004				2005			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$15.90	$18.72	$18.16	$23.50	$24.77	$26.22	$37.31	$39.82
High	$20.02	$22.75	$25.16	$30.34	$30.64	$36.75	$48.86	$50.01

Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our credit agreements, as discussed in Note 4 to the consolidated financial statements, and we presently intend to continue a policy of using retained earnings for expansion of our business.

We had approximately 258 stockholders of record as of December 31, 2005.

Equity Compensation Plan Information

Information regarding our equity compensation plans, including both shareholder approved plans and plans not approved by shareholders, is set forth in Proxy Statement for our annual meeting to be held May 9, 2006 (Proxy Statement), which Proxy Statement is to be filed within 120 days after Registrant s fiscal year end of December 31, 2005, and which information is incorporated herein by reference.

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Item 6. Selected Financial Data

	2005	2004	2003	2002	2001
Total Revenues	$ 423,226,489	$ 310,276,774	$ 208,900,983	$ 149,969,811	$ 183,807,490
Income (Loss) Before Income Taxes and Change in Accounting Principle (1)	$ 178,439,551	$ 101,440,242	$ 50,739,178	$ 18,408,289	($ 34,192,333)
Net Income (Loss)	$ 115,778,456	$ 68,450,917	$ 29,893,812	$ 11,923,227	($ 22,347,765)
Net Cash Provided by Operating Activities	$ 285,333,484	$ 182,582,887	$ 110,827,279	$ 71,626,314	$ 139,884,255
Per Share Data					
Weighted Average Shares Outstanding(1)	28,496,275	27,822,413	27,357,579	26,382,906	24,732,099
Earnings (Loss) per Share Basic(1)	$ 4.06	$ 2.46	$ 1.09	$ 0.45	($ 0.90)
Earnings (Loss) per Share Diluted(1)	$ 3.95	$ 2.41	$ 1.08	$ 0.45	($ 0.90)
Shares Outstanding at Year-End	29,009,530	28,089,764	27,484,091	27,201,509	24,795,564
Book Value per Share at Year-End	$ 20.94	$ 16.88	$ 14.46	$ 13.42	$ 12.61
Market Price(1)					
High	$ 50.01	$ 30.34	$ 18.00	$ 20.58	$ 37.70
Low	$ 24.77	$ 15.90	$ 7.60	$ 6.80	$ 16.66
Year-End Close	$ 45.07	$ 28.94	$ 16.85	$ 9.67	$ 20.20
Effect on Net Income and Earnings Per Share From Changes in Accounting Principles (2)					
Cumulative Effect of Change in Accounting Principle (Net of Taxes)			($ 4,376,852)		($ 392,868)
Effect per Share Basic			($ 0.16)		($ 0.01)
Effect per Share Diluted			($ 0.16)		($ 0.01)
Assets					
Current Assets	$ 115,055,135	$ 54,385,996	$ 33,460,957	$ 29,768,199	$ 36,752,980
Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and	$ 1,079,033,739	$ 923,438,160	$ 815,807,003	$ 721,617,941	$ 628,304,060

Amortization					
Total Assets	$ 1,204,412,622	$ 990,573,147	$ 859,838,544	$ 767,005,859	$ 671,684,833
Liabilities					
Current Liabilities	$ 98,421,014	$ 68,618,291	$ 69,353,342	$ 46,884,184	$ 73,245,335
Long-Term Debt	$ 350,000,000	$ 357,500,000	$ 340,254,783	$ 324,271,973	$ 258,197,128
Total Liabilities	$ 597,094,455	$ 516,401,007	$ 462,447,280	$ 401,932,675	$ 359,032,113
Stockholders Equity	$ 607,318,167	$ 474,172,140	$ 397,391,264	$ 365,073,184	$ 312,652,720
Number of Employees	311	272	241	234	209
Producing Wells					
Swift Operated	898	835	870	820	854
Outside Operated	69	97	128	112	381
Total Producing Wells	967	932	998	932	1,235
Wells Drilled (Gross)	64	66	75	36	53
Proved Reserves					
Natural Gas (Mcf)	287,473,150	318,246,294	335,804,862	326,731,672	324,912,125
Oil, NGL, & Condensate (barrels)	79,053,056	80,267,208	80,759,903	70,438,963	53,482,636
Total Proved Reserves (Mcf equivalent)	761,791,482	799,849,539	820,364,284	749,365,449	645,807,939
Production (Mcf equivalent)(3)	59,589,526	58,318,502	53,158,384	49,752,346	44,791,202
Average Sales Price					
Natural Gas (per Mcf)	$ 5.23	$ 4.12	$ 3.42	$ 2.30	$ 4.23
Natural Gas Liquids (per barrel)(4)	$ 28.04	$ 22.52	$ 17.60	$ 12.82	
Oil (per barrel)(4)	$ 53.63	$ 40.24	$ 29.89	$ 24.52	$ 22.64
Mcf Equivalent	$ 7.11	$ 5.34	$ 3.97	$ 2.84	$ 4.05

1 Amounts have been retroactively restated in all periods presented to give recognition to: (a) an equivalent change in capital structure as a result of two 10% stock dividends, one in September 1994, the other in October 1997; (b) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, Earnings per Share, and (c) the adoption in 2003 of Statement of Financial Accounting Standards No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, which affected our presentation of 1999 results by reclassifying the loss on early extinguishment of debt from an extraordinary item to an operating item.

2 We adopted SFAS No. 143, Accounting for Asset Retirement Obligations on January 1, 2003. We adopted SFAS No. 133 Accounting for Derivative Instruments and Hedging Transactions on January 1, 2001. As of January 1, 1994, we changed our revenue recognition policy for earned interests.

3 Natural gas production from 1995 to 2000 includes volumes under a production payment agreement ranging from 1.2 Bcfe in 1995 to 0.4 Bcfe in 2000.

4 Prior to 2002, we combined NGLs with natural gas for reporting purposes.

2000	1999	1998	1997	1996	1995
$ 191,624,946	$ 110,671,007	$ 82,469,221	$ 74,712,180	$ 56,298,026	$ 25,092,230
92,449,488	$ 29,736,151	($73,391,581)	$ 33,129,606	$ 28,785,783	$ 6,894,537
$ 59,184,008	$ 19,286,574	($48,225,204)	$ 22,310,189	$ 19,025,450	$ 4,912,512
$ 128,197,227	$ 73,603,426	$ 54,249,017	$ 55,255,965	$ 37,102,578	$ 14,376,463
21,244,684	18,050,106	16,436,972	16,492,856	15,000,901	10,035,143
$ 2.79	$ 1.07	($2.93)	$ 1.35	$ 1.27	$ 0.49
$ 2.51	$ 1.07	($2.93)	$ 1.26	$ 1.25	$ 0.49
24,608,344	20,823,729	16,291,242	16,459,156	15,176,417	12,509,700
$ 13.50	$ 8.18	$ 6.71	$ 9.69	$ 9.41	$ 7.46
$ 43.50	$ 13.31	$ 21.00	$ 34.20	$ 28.86	$ 11.48
$ 9.75	$ 5.69	$ 6.94	$ 16.93	$ 9.89	$ 7.05
$ 37.63	$ 11.50	$ 7.38	$ 21.06	$ 27.16	$ 10.91
$ 41,872,879	$ 50,605,488	$ 35,246,431	$ 29,981,786	$ 101,619,478	$ 43,380,454
$ 524,052,828	$ 392,986,589	$ 356,711,711	$ 301,312,847	$ 200,010,375	$ 125,217,872
$ 572,387,001	$ 454,299,414	$ 403,645,267	$ 339,115,390	$ 310,375,264	$ 175,252,707
$ 64,324,771	$ 34,070,085	$ 31,415,054	$ 28,517,664	$ 32,915,616	$ 40,133,269
$ 134,729,485	$ 239,068,423	$ 261,200,000	$ 122,915,000	$ 115,000,000	$ 28,750,000
$ 240,232,846	$ 283,895,297	$ 294,282,628	$ 179,714,470	$ 167,613,654	$ 81,906,742
$ 332,154,155	$ 170,404,117	$ 109,362,639	$ 159,400,920	$ 142,761,610	$ 93,345,965
181	173	203	194	191	176
817	769	836	650	842	767
711	788	917	917	986	3,316
1,528	1,557	1,753	1,567	1,828	4,083
70	27	75	182	153	76
418,613,976	329,959,750	352,400,835	314,305,669	225,758,201	143,567,520
35,133,596	20,806,263	13,957,925	7,858,918	5,484,309	5,421,981
629,415,552	454,797,327	436,148,385	361,459,177	258,664,055	176,099,406
42,356,705	42,874,303	39,030,030	25,393,744	19,437,114	11,186,573
$ 4.24	$ 2.40	$ 2.08	$ 2.68	$ 2.57	$ 1.77

$	29.35	$	16.75	$	11.86	$	17.59	$	19.82	$	15.66
$	4.47	$	2.54	$	2.05	$	2.72	$	2.71	$	2.01

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

You should read the following discussion and analysis in conjunction with our financial information and our audited consolidated financial statements and accompanying notes for the years ended December 31, 2005, 2004, and 2003 included with this report. The following information contains forward-looking statements, see Forward-Looking Statements on page 43 of this report.

Overview

Swift Energy had record net income, cash flow, and production for 2005. Net income increased 69% to $115.8 million and cash flow increased 56% to $285 million over 2004 net income and cash flow. Production increased 2% to 59.6 Bcfe over 2004 production. We also had record revenues of $423.2 million for 2005, an increase of 36% over 2004 levels, and became the largest crude oil producer in Louisiana. Swift Energy also dealt with challenges presented by the damage and disruption caused by Hurricanes Katrina and Rita in the last half of 2005. We ended 2005 with total proved reserves of 762 Bcfe, a decrease of 5% from year-end 2004 levels. Revenues, production levels, and reserves for 2005 were lower than our pre-hurricane guidance as a result of production shut-ins and deferred drilling necessitated by Hurricanes Katrina and then Rita. We estimate that the effect of these hurricanes deferred approximately 6.0 to 6.5 Bcfe of production and deferred the drilling of approximately 10 to 15 domestic wells into 2006. Our weighted average sales price increased 33% to $7.11 per Mcfe for 2005 from $5.34 in 2004. The strong commodity prices during 2005 supported the increase in our revenues as compared to 2004 despite the impact of the hurricanes on production volumes.

Our efforts and capital throughout 2005 remained primarily focused on infrastructure improvements, increased production, and the development of long-lived reserves through exploration and exploitation activities primarily in our four regions: South Louisiana, South Texas, Toledo Bend, and New Zealand. We expect to continue this focus throughout 2006. We are reviewing further potential capacity increase of the facilities in Lake Washington, and expect the new 3-D seismic over the Cote Blanche Island area to be completed in the third quarter of 2006, and plan to acquire seismic on our offshore Kaheru exploration permit in New Zealand.

Our overall costs and expenses increased in 2005, and we expect to manage our costs and expenses to remain at this level in 2006. The largest increase in these costs and expenses is due to increased depreciation, depletion and amortization expense as a result of increased estimates for future development costs and additional capital expenditures during 2005. We experienced higher costs due to increased oil production in Lake Washington, along with higher severance taxes due to increased revenues. We also saw an increase in our general and administrative expenses due to an increased workforce and stock compensation expense associated with the issuance of restricted stock. Although our lease operating costs were less than originally anticipated through the first six months of 2005, due to lower than expected chemical, repair and maintenance costs as well as no significant work-over activity, lease operating costs were adversely affected in the second half of 2005 due to Hurricanes Katrina and Rita. During the last half of 2005, we recorded approximately $10.8 million of costs related to Hurricane Katrina and $4.1 million related to Hurricane Rita, and we expect additional hurricane related costs to be incurred in 2006. Approximately $2.0 million of the total costs were expensed to lease operating expense, net of estimated insurance reimbursement, in 2005. The remainder of the costs related to capital projects. We expect cost pressures to continue to affect the industry throughout 2006, especially along the Gulf Coast following the hurricanes, with tightening availability of crews as well as increasing costs of services and basic equipment.

Year-end 2005 proved reserves of 761.8 Bcfe, representing a 5% decline for the year, were 51% crude oil, 38% natural gas and 11% NGLs, compared to year-end 2004 proved reserves of 799.8 Bcfe, which were 49% crude oil, 40% natural gas and 11% NGLs. Proved developed reserves decreased slightly to 50% of total reserves at year-end 2005, compared to 56% the previous year. Domestic proved reserves decreased at year-end 2005 to 644.0 Bcfe and included the acquisition of reserves in the South Bearhead Creek field, which was predominantly proved undeveloped. Proved reserves in New Zealand decreased to 117.8 Bcfe at year-end 2005, primarily attributable to 2005 production and downward revisions in the Kauri sands in the Rimu/Kauri area. In 2005, we focused our drilling activity, both domestically and in New Zealand, on proved undeveloped locations that helped maximize production in a high-price environment, but which also resulted in smaller additions to proved reserves.

Our financial position remains strong and flexible, allowing us to take advantage of future opportunities in organic growth through drilling and strategic growth through acquisitions. Our financial ratios have also continued to improve. Our debt to PV-10 ratio decreased to 11% at December 31, 2005 compared to 18% at December 31, 2004, due to higher crude oil and natural gas prices and a slight decrease in our total debt. Higher commodity prices have increased our PV-10 Value. Our debt to capitalization ratio was 37% at December 31, 2005 compared to 43% at year-end 2004, as debt levels decreased slightly in 2005 and retained earnings increased as a result of the current period profit. Including our cash on hand at year-end 2005, our net debt to capital ratio would have been 33% and our net debt per Mcfe would be $0.38 per Mcfe.

There are a number of factors that support our belief that Swift Energy s performance for 2006 will be strong. We think that strong commodity prices will continue over the foreseeable future, based in part on forward-strip pricing. Although production was impacted by the hurricane activity in the second half of 2005, all of Swift Energy s operations in the South Louisiana region are back on production at or above pre-Katrina production levels, except for the Cote Blanche Island field, and the major facility expansion projects at the Lake Washington area are in the final commissioning stages. Cote Blanche Island is expected to be back online by the end of the first quarter of 2006. Our merged 3-D seismic data offsets around our fields in southern Louisiana has yielded success in our exploration and development activities, as demonstrated by our year-end drilling successes at our Newport and Bondi prospects in the Lake Washington area. Continued work-over and recompletion activity is expected to take place in 2006, particularly in the Bay de Chene and Cote Blanche Island fields in southern Louisiana; however, this work has been delayed somewhat due to our recovery efforts from Hurricanes Katrina and Rita. We ve also acquired additional property in our Toledo Bend region during the fourth quarter of 2005, the South Bearhead Creek property. The Piakau discovery in New Zealand has yielded positive results, although further reservoir delineation is required. Our diversified drilling portfolio positions us for higher impact exploration drilling as well as expanded exploitation efforts in 2006.

Results of Operations Years Ended 2005, 2004, and 2003

Revenues. Our revenues in 2005 increased by 36% compared to revenues in 2004, and our revenues in 2004 increased by 49% compared to 2003 revenues due primarily to increases in each successive year in oil and natural gas prices and in production from our Lake Washington and Rimu/Kauri areas. Revenues from our oil and gas sales comprised substantially all of total revenues for 2005, 2004, and 2003. Crude oil production was 52% of our production volumes in 2005, 49% in 2004, and 38% in 2003. Natural gas production was 40% of our production volumes in 2005, 41% in 2004, and 53% in 2003. Domestic production was 72% of our total production volumes in both 2005 and 2004, and 64% in 2003.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2005, 2004, and 2003:

	Oil and Gas Sales (In millions)			Oil and Gas Sales Volume (Bcfe)		
Area	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
AWP Olmos	$ 61.7	$ 49.9	$ 43.7	7.7	9.0	8.4
Brookeland	20.4	18.0	16.4	2.9	3.4	3.9
Lake Washington	229.2	152.3	59.5	26.7	23.2	12.1
Masters Creek	17.9	21.0	25.7	2.4	3.7	5.7
Other	26.7	17.5	18.9	3.3	2.8	3.7
Total Domestic	$ 355.9	$ 258.7	$ 164.2	43.0	42.1	33.8
Rimu/Kauri	41.6	24.5	11.6	8.2	5.3	3.3
TAWN	26.3	28.1	35.2	8.3	11.0	16.1
Total New Zealand	$ 67.9	$ 52.6	$ 46.8	16.5	16.3	19.4
Total	$ 423.8	$ 311.3	$ 211.0	59.6	58.3	53.2

Oil and gas sales in 2005 increased by 36%, or $112.5 million, from the level of those revenues for 2004, and our net sales volumes in 2005 increased by 2%, or 1.3 Bcfe, over net sales volumes in 2004. Average prices for oil increased to $53.63 per Bbl in 2005 from $40.24 per Bbl in 2004. Average natural gas prices increased to $5.23 per Mcf in 2005 from $4.12 per Mcf in 2004. Average NGL prices increased to $28.04 per Bbl in 2005 from $22.52 per Bbl in 2004.

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In 2005, our $112.5 million increase in oil, NGL, and natural gas sales resulted from:

Price variances that had a $100.0 million favorable impact on sales, of which $69.1 million was attributable to the 33% increase in average oil prices received, $26.3 million was attributable to the 27% increase in natural gas prices and $4.6 million was attributable to the 24% increase in NGL prices; and

Volume variances that had a $12.5 million favorable impact on sales, with $17.6 million of increases attributable to the 0.4 million Bbl increase in oil sales volumes, offset by a decrease of $4.6 million due to the 0.2 million Bbl decrease in NGL sales volumes, and a decrease of $0.5 million due to the 0.1 Bcf decrease in natural gas sales volumes.

Oil and gas sales in 2004 increased by 48%, or $100.3 million, from the level of those revenues for 2003, and our net sales volumes in 2004 increased by 10%, or 5.2 Bcfe, over net sales volumes in 2003. Average prices for oil increased to $40.24 per Bbl in 2004 from $29.89 per Bbl in 2003. Average natural gas prices increased to $4.12 per Mcf in 2004 from $3.42 per Mcf in 2003. Average NGL prices increased to $22.52 per Bbl in 2004 from $17.60 per Bbl in 2003.

In 2004, our $100.3 million increase in oil, NGL, and natural gas sales resulted from:

Price variances that had a $70.6 million favorable impact on sales, of which $48.9 million was attributable to the 35% increase in average oil prices received, $16.6 million was attributable to the 20% increase in natural gas prices and $5.1 million was attributable to the 28% increase in NGL prices; and

Volume variances that had a $29.7 million favorable impact on sales, with $40.4 million of increases attributable to the 1.4 million Bbl increase in oil sales volumes and $3.8 million to the 217,000 Bbl increase in NGL sales volumes, offset by a decrease of $14.5 million due to the 4.3 Bcf decrease in natural gas sales volumes primarily from our TAWN area in New Zealand.

The following table provides additional information regarding our quarterly oil and gas sales:

	Sales Volume				**Average Sales Price**		
	Oil (MBbl)	**NGL (MBbl)**	**Gas (Bcf)**	**Combined (Bcfe)**	**Oil (Bbl)**	**NGL (Bbl)**	**Natural Gas (Mcf)**
2003:							
First	690	174	7.6	12.9	$ 32.73	$ 21.90	$ 3.71
Second	822	211	7.1	13.3	$ 27.97	$ 15.81	$ 3.47
Third	917	247	6.7	13.6	$ 29.24	$ 16.81	$ 3.17
Fourth	941	191	6.6	13.4	$ 30.10	$ 16.71	$ 3.29
Total	3,370	823	28.0	53.2	$ 29.89	$ 17.60	$ 3.42
2004:							
First	1,124	277	5.9	14.3	$ 34.14	$ 22.30	$ 3.64
Second	1,142	269	5.8	14.3	$ 37.24	$ 18.84	$ 4.19
Third	1,076	251	6.0	13.9	$ 41.99	$ 23.33	$ 3.97
Fourth	1,380	243	6.1	15.9	$ 46.33	$ 26.01	$ 4.67
Total	4,722	1,040	23.7	58.3	$ 40.24	$ 22.52	$ 4.12
2005:							
First	1,321	223	6.3	15.5	$ 47.66	$ 26.79	$ 4.25
Second	1,426	209	6.1	15.9	$ 50.24	$ 22.95	$ 4.67

Third	1,059	204	5.9	13.5	$ 59.66	$ 31.84	$ 5.29
Fourth	1,353	202	5.3	14.7	$ 58.31	$ 30.83	$ 6.97
Total	5,159	838	23.6	59.6	$ 53.63	$ 28.04	$ 5.23

Costs and Expenses. Our expenses in 2005 increased $36.0 million, or 17%, compared to 2004 expenses. The majority of the increase was due to a $25.9 million increase in DD&A, an $11.8 million increase in severance and other taxes, and a $6.1 million increase in lease operating costs, all of which are primarily due to increased commodity prices and production volumes in 2005. This increase was partially offset by the absence of $9.5 million of debt retirement costs incurred in 2004. Our expenses in 2004 increased $50.7 million, or 32%, compared to 2003 expenses. The majority of the increase was due to an $18.5 million increase in DD&A, an $11.4 million increase in severance and other taxes, and a $7.4 million increase in lease operating costs, all of which were primarily due to increased production volumes and oil and gas commodity prices in 2004.

Our 2005 general and administrative expenses, net, increased $4.4 million, or 25%, from the level of such expenses in 2004, while 2004 general and administrative expenses, net, increased $3.7 million, or 26%, over 2003 levels. The increase in both 2005 and 2004 were primarily due to increased salaries and burdens associated with our expanded workforce and the expensing of restricted stock compensation in 2005. A portion of the increase in 2004 costs was also attributable to Sarbanes-Oxley Act compliance costs increasing over the prior year. These costs, while remaining high, have stabilized from 2004 to 2005. For the years 2005, 2004, and 2003, our capitalized general and administrative costs totaled $18.8 million, $13.1 million, and $11.5 million, respectively. Our net general and administrative expenses per Mcfe produced increased to $0.37 per Mcfe in 2005 from $0.30 per Mcfe in 2004 and $0.27 per Mcfe in 2003. Our 2005 cost per Mcfe was adversely affected by the approximate 6.0 to 6.5 Bcfe of production that was deferred, and not produced in 2005, because of Hurricanes Katrina and Rita. The portion of supervision fees recorded as a reduction to general and administrative expenses was $7.8 million for 2005, $5.8 million for 2004, and $3.6 million for 2003.

DD&A increased $25.9 million, or 32%, in 2005 from 2004 levels, while 2004 DD&A increased $18.5 million, or 29%, from 2003 levels. Domestically, DD&A increased $18.8 million in 2005 due to increases in the depletable oil and gas property base, slightly higher production in the 2005 period and lower reserves volumes. In New Zealand, DD&A increased by $7.1 million in 2005 due to the same reasons. In 2004, our domestic DD&A increased by $17.6 million due to increases in the depletable oil and gas property base, higher production in the 2004 period and slightly lower reserves volumes. Our New Zealand DD&A increased by $0.9 million in 2004 due to increases in the depletable oil and gas property base along with lower reserves volumes, partially offset by lower production in the 2004 period. Our DD&A rate per Mcfe of production was $1.80 in 2005, $1.40 in 2004, and $1.19 in 2003, resulting from increases in per unit cost of reserves additions.

We recorded $0.8 million, $0.7 million, and $0.9 million of accretions to our asset retirement obligation in 2005, 2004, and 2003, respectively.

Our lease operating costs per Mcfe produced were $0.79 in 2005, $0.71 in 2004 and $0.64 in 2003. Our 2005 cost per Mcfe was adversely affected by the approximate 6.0 to 6.5 Bcfe of production that was deferred, and not produced in 2005, because of Hurricanes Katrina and Rita. There were no supervision fees recorded as a reduction to production costs in 2005 or 2004, while there were $1.5 million in 2003. Our lease operating costs in 2005 increased $6.1 million, or 15%, over the level of such expenses in 2004, while 2004 costs increased $7.4 million, or 22% over 2003 levels. Approximately $4.7 million of the increase in lease operating costs during 2005 was related to our domestic operations, which increased primarily due to hurricane related costs, along with increased oil production from our Lake Washington area. Our lease operating cost in New Zealand increased in 2005 by $1.4 million due to increases in plant operating costs related to increased staffing in this area. Approximately $1.2 million of the increase in 2004 was due to our New Zealand operations as production increased over 2003 levels.

Severance and other taxes increased $11.8 million, or 39% over 2004 levels, while in 2004 these taxes increased $11.4 million, or 60% over 2003 levels. The increases were due primarily to higher commodity prices and increased Lake Washington and Rimu/Kauri production in each of the periods. Severance taxes on oil in Louisiana are 12.5% of oil sales, which is higher than in the other states where we have production. As our percentage of oil production in Louisiana increases, the overall percentage of severance costs to sales also increases. Severance and other taxes, as a percentage of oil and gas sales, were approximately 10.0%, 9.8% and 9.0% in 2005, 2004 and 2003, respectively.

Our total interest cost in 2005 was $32.1 million, of which $7.2 million was capitalized. Our total interest cost in 2004 was $34.2 million, of which $6.5 million was capitalized. Our total interest cost in 2003 was $34.2 million, of which $6.8 million was capitalized. Interest expense on our 7-5/8% senior notes due 2011 issued in June 2004, including amortization of debt issuance costs, totaled $11.9 million in 2005 and $6.2 million in 2004. Interest expense on our 9-3/8% senior subordinated notes due 2012 issued in April 2002, including amortization of debt issuance costs, totaled $19.2 million in both 2005 and 2004, and $19.1 million in 2003. Interest expense on our 10-1/4% senior subordinated notes issued in August 1999 and repurchased and retired in 2004, including amortization of debt issuance costs, totaled $7.4 million in 2004 and $13.2 million in 2003. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.0 million in 2005, $1.5 million in 2004, and $1.6 million in 2003. Other interest cost was $0.3 million in 2003. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in 2005 was primarily due to the lower interest rate applicable to the 7-5/8% notes issued in June 2004 versus the 10-1/4% notes retired at that time. The increase in interest expense in 2004 was due to lower capitalized interest than in 2003.

In 2004, we incurred $9.5 million of debt retirement costs related to the repurchase and redemption of our 10-1/4% senior subordinated notes due 2009. The costs were comprised of approximately $6.5 million of premiums paid to repurchase the notes, $2.2 million to write-off unamortized debt issuance costs, $0.6 million to write-off unamortized debt discount and approximately $0.2 million of other costs.

Our overall effective tax rate was 35.1% for 2005, and 32.5% for 2004 and 2003. The effective tax rate for 2005, 2004 and 2003 was lower than the statutory tax rates primarily due to reductions from the New Zealand statutory rate attributable to the currency effect on the New Zealand deferred tax calculation. The provision for 2005 included the reversal of a New Zealand repatriation allowance offset by an adjustment to correct an error in a prior year s tax returns and higher state tax rate estimates. The effective tax rate for 2004 included favorable corrections to tax basis amounts discovered while preparing the prior year s tax returns, partially offset by higher deferred state income taxes. Income tax expense in 2003 included higher domestic state income taxes and other items.

As discussed in Note 1 to the consolidated financial statements, we adopted SFAS No. 143 Accounting for Asset Retirement Obligations on January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of $4.4 million, which was recorded as a cumulative effect of change in accounting principle in the 2003 consolidated statement of income.

Net Income. Our net income in 2005 of $115.8 million was 69% higher than our 2004 net income of $68.5 million due to higher commodity prices and increased production.

Our net income in 2004 of $68.5 million was 129% higher than our 2003 net income of $29.9 million due to higher commodity prices and increased production.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2005 are as follows:

	2006	2007	2008	2009	2010	Thereafter	Total
				(In thousands)			
Non-cancelable operating leases (1)	$ 3,404	$ 3,401	$ 3,042	$ 2,655	$ 2,751	$ 13,394	$ 28,647
Asset retirement obligation(2)	261	261	261	261	261	18,051	19,356
Construction at the corporate office	7,337						7,337
Drilling rigs, seismic and pipe inventory	28,110	1,807					29,917
7-5/8% senior notes due 2011(3)						150,000	150,000
9-3/8% senior subordinated notes due 2012(3)						200,000	200,000
Credit facility(4)							
Total	$ 39,112	$ 5,469	$ 3,303	$ 2,916	$ 3,012	$ 381,445	$ 435,257

(1) Our most significant office lease is in Houston, Texas extends until 2015.

(2) Amounts shown by year are the fair values at December 31, 2005.

(3) Amounts do not include the interest obligation, which is paid semiannually.

(4) The credit facility expires in October 2008 and these amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

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Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil has increased over the last two years and is at historical highs when compared to longer-term historical prices. Factors such as worldwide supply disruptions, worldwide economic conditions, weather conditions, fluctuating currency exchange rates, political conditions in major oil producing regions, especially the Middle East, can cause fluctuations in the price of oil. Domestic natural gas prices continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas.

Income Tax Regulations

The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such tax laws can differ.

Liquidity and Capital Resources

During 2005, we largely relied upon our net cash provided by operating activities of $285.3 million to fund capital expenditures of $235.5 million and $28.9 million of acquisitions. During 2004, we relied upon our net cash provided by operating activities of $182.6 million, the issuance of our 7-5/8% senior notes due 2011, proceeds from the sale of non-core properties and equipment of $5.1 million, less the repayment of our 10-1/4% senior subordinated notes due 2009 to fund capital expenditures of $171.1 million and acquisitions of $27.2 million.

Net Cash Provided by Operating Activities. For 2005, our net cash provided by operating activities was $285.3 million, representing a 56% increase as compared to $182.6 million generated during 2004. The $102.8 million increase in 2005 was primarily due to an increase of $112.5 million in oil and gas sales, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher domestic production and severance taxes as a result of higher commodity prices. In 2004, net cash provided by operating activities increased by 65% to $182.6 million, as compared to $110.8 million in 2003. The 2004 increase of $71.8 million was primarily due to an increase of $100.3 million in oil and gas sales, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher domestic production and severance taxes as a result of higher commodity prices in 2004.

Accounts Receivable. Included in the Accounts receivable balance, which totaled $39.0 million at December 31, 2004, on the accompanying balance sheets, were approximately $2.3 million of receivables related to hydrocarbon volumes produced from 2001 and 2002 that had been disputed since early 2003. As a result of the dispute, we did not record a receivable with regard to any 2003 disputed volumes and our contract governing these sales expired in 2003. Based on settlement discussions, we settled our claim with this counter-party in July 2005 by receiving a cash payment for less than our gross receivable. Accordingly, in the second quarter of 2005, we increased our reserve for this claim by approximately $0.6 million, which is recorded in Price-risk management and other, net on the accompanying statements of income.

We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2005 and 2004, we had an allowance for doubtful accounts of less than $0.1 million and $0.5 million, respectively. The allowance for doubtful accounts has been deducted from the total Accounts receivable balances on the accompanying balance sheets.

Sarbanes-Oxley Compliance Costs. We have incurred substantial costs to comply with the Sarbanes-Oxley Act of 2002. These expenditures have reduced our net cash provided by operating activities in each of the last three years. In 2005, 2004 and 2003, Sarbanes-Oxley Act compliance costs, including internal and external costs, are reflected in General and administrative, net on the accompanying statements of income.

Existing Credit Facility. We had no borrowings under our bank credit facility at December 31, 2005, and $7.5 million in outstanding borrowings at December 31, 2004. Our bank credit facility at December 31, 2005 consisted of a $400.0 million revolving line of credit with a $250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at $250.0 million, effective November 1, 2005. We maintain the commitment amount at $150.0 million, which amount was set at our request effective May 9, 2003. Under the terms of our bank credit facility, we can increase this commitment amount to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. Our revolving credit facility includes requirements to maintain certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt. We are in compliance with the provisions of this agreement.

Our access to funds from our credit facility is not restricted under any material adverse condition clause, a clause that is common for credit agreements to include. A material adverse condition clause can remove the obligation of the banks to fund the credit line if any condition or event would reasonably be expected to have an adverse or material effect on our operations, financial condition, prospects or properties, and would impair our ability to make timely debt repayments. Our credit facility includes covenants that require us to report events or conditions having a material adverse effect on our financial condition. The obligation of the banks to fund the credit facility is not conditioned on the absence of a material adverse effect.

Working Capital. Our working capital improved from a deficit of $14.2 million at December 31, 2004, to a surplus of $16.6 million at December 31, 2005. The improvement primarily resulted from an increase in cash and cash equivalents and an increase in accounts receivable for oil and gas sales due to higher sales volumes and commodity prices.

Repurchase of 10-1/4% Senior Subordinated Notes Due 2009. In June 2004, we repurchased $32.1 million of our 10-1/4 senior subordinated notes due 2009 pursuant to a tender offer, and recorded debt retirement costs of $2.7 million related to this repurchase. In July 2004, we repurchased approximately $0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining $92.5 million of these notes. We have recorded a total of $9.5 million in debt retirement costs related to the total repurchase of these notes.

Debt Maturities. Our credit facility extends until October 1, 2008. Our $150.0 million of 7-5/8% senior notes mature July 15, 2011, and our $200.0 million of 9-3/8% senior subordinated notes mature May 1, 2012.

Capital Expenditures. In 2005 we relied upon our net cash provided by operating activities of $285.3 million to fund capital expenditures of $235.5 million and acquisitions of $28.9 million. Our total capital expenditures of approximately $264.5 million in 2005 included:

Domestic expenditures of $215.8 million as follows:

- $111.0 million for drilling and developmental activity costs, predominantly in our Lake Washington area;
- $29.6 million on property acquisitions, including $28.9 million to acquire properties in the South Bearhead Creek field;
- $36.8 million on exploratory drilling, mainly in our Lake Washington area;
- $34.4 million of domestic prospect costs, principally prospect leasehold, 3-D seismic activity, and geological costs of unproved prospects;
- $3.6 million primarily for a field office building, computer equipment, software, furniture, and fixtures;
- $0.3 million on gas processing plants in the Brookeland and Masters Creek areas; and
- less than $0.1 million on field compression facilities.

New Zealand expenditures of $48.7 million as follows:

- $27.2 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;

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- $13.6 million on exploratory drilling;
- $6.9 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $0.8 million on gas processing plants; and
- $0.2 million for computer equipment, software, furniture, and fixtures.

We have spent considerable time and capital in 2005 and 2004 on significant facility capacity upgrades in the Lake Washington field to increase facility capacity to approximately 28,000 barrels per day for crude oil, up from 9,000 barrels per day capacity in the first quarter of 2003. We have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility.

We successfully completed 45 of 64 wells in 2005, for a success rate of 70%. Domestically, we completed 37 of 45 development wells for a success rate of 82% and completed five of nine exploration wells. A total of 32 wells were drilled in the Lake Washington area, of which 21 were completed, and 18 wells were drilled in the AWP Olmos area, all of which were completed. In New Zealand, we completed two of five development wells, and one of five exploratory wells.

Our 2006 capital expenditure budget is $300 million to $325 million, net of $5 million to $10 million of dispositions and excluding any acquisitions. Approximately 85% of the budget is targeted for domestic activities, with about 15% planned for activities in New Zealand. We plan to spend $175 million to $195 million in our South Louisiana region, which includes Lake Washington, Bay de Chene and Cote Blanche Island. Of this amount, approximately $40 million to $50 million will be focused in Bay de Chene and Cote Blanche Island and includes approximately $11 million designated for the Cote Blanche Island 3-D seismic acquisition planned for 2006. The $5 million to $10 million of dispositions relate to non-core properties planned for later in 2006. We expect that our 2006 capital expenditures to remain below our cash flows provided from operating activities during 2006, similar to 2005. During 2006, we may utilize our free cash flow to expand our capital budget and accelerate our drilling inventory plans to take advantage of current commodity prices, potential acquisitions, debt repayment or stock repurchases. For 2006, we are targeting an increase of 14% to 18% for total production and an increase of 5% to 8% for proved reserves, over the 2005 levels.

Our capital expenditures were approximately $171.1 million in 2004 and $144.5 million in 2003. During 2004, we relied upon our net cash provided by operating activities of $182.6 million, the issuance of our 7-5/8% senior notes due 2011, proceeds from the sale of non-core properties and equipment of $5.1 million, less the repayment of our 10-1/4% senior subordinated notes due 2009 to fund capital expenditures of $171.1 million and acquisitions of $27.2 million. During 2003, we relied upon our net cash provided by operating activities of $110.8 million, proceeds from bank borrowings of $15.9 million, and proceeds from the sale of non-core properties and equipment of $10.2 million to fund capital expenditures of $144.5 million. Our total capital expenditures in 2004 of approximately $198.3 million included:

Domestic expenditures of $162.5 million as follows:

- $87.7 million for drilling and developmental activity costs, predominantly in our Lake Washington area;
- $31.8 million on property acquisitions, including $27.2 million to acquire properties in the Bay de Chene and Cote Blanche Island fields;
- $28.7 million of domestic prospect costs, principally prospect leasehold, Lake Washington 3-D seismic activity, and geological costs of unproved prospects;
- $9.9 million on exploratory drilling, mainly in our Lake Washington area;
- $2.5 million primarily for a field office building, computer equipment, software, furniture, and fixtures;

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- $1.3 million on field compression facilities; and
- $0.6 million on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand expenditures of $35.8 million as follows:

- $26.7 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;
- $7.0 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $1.2 million on gas processing plants;
- $0.7 million on exploratory drilling; and
- $0.2 million for computer equipment, software, furniture, and fixtures.

In 2004, we participated in drilling 44 domestic development wells and ten domestic exploratory wells, of which 37 development wells and four exploratory wells were completed. In New Zealand we drilled 11 development wells, of which ten were completed, and one unsuccessful exploratory well.

New Accounting Principles

EITF 04-05 addresses when a limited partnership should be consolidated by its general partner. EITF 04-05 presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or participating rights would be considered substantive and preclude consolidation by the general partner. The FASB ratified the EITF consensus at the June 2005 EITF meeting. We do not believe this EITF will have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. SFAS No. 123R requires all employee share-based payments, including grants of employee stock options, to be recognized in the financial statements based on their fair values. SFAS No. 123 discontinues the ability to account for these equity instruments under the intrinsic value method as described in APB Opinion No. 25. SFAS No. 123R requires the use of an option pricing model for estimating fair value, which is amortized to expense over the service periods. The requirements of SFAS No. 123R are effective for fiscal periods beginning after June 15, 2005. SFAS No. 123R permits public companies to adopt its requirements using one of two methods, we have chosen the modified prospective method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS No. 123R for all share-based payments granted after the effective date and based on the requirements of SFAS No. 123 for all awards granted to employees prior to the adoption date of SFAS No. 123R that remain unvested on the adoption date.

In April 2005, the SEC issued a release announcing that it would provide for a phased-in implementation process for SFAS No. 123R. As a result, our required date to adopt SFAS No. 123R was January 1, 2006. Also in April 2005, the SEC issued Staff Accounting Bulleting No. 107, Share-Based Payment, which provides guidance on the implementation of SFAS No. 123R. SAB No. 107 provides guidance on valuing options, estimating volatility and expected terms of the option awards, and discusses the SEC s views on share-based payment transactions with non-employees, the capitalization of compensation cost and accounting for income tax effects of share-based payment arrangements upon adoption of SFAS No. 123R.

We will adopt the provisions of SFAS No. 123R effective January 1, 2006 using the modified prospective method. As permitted by Statement 123, the Company previously accounted for share-based payments to employees using APB Opinion No. 25 s intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of Statement No. 123R s fair value method is expected to have a significant impact on our results of operations. However, it will have no impact on our overall financial position. We use the Black-Scholes-Merton formula to estimate the value of stock options granted to employees and expect to continue to use this acceptable option valuation model after the required adoption of SFAS No. 123R. The significance of the impact of adoption will depend on levels of outstanding unvested share-based payments on the date of adoption and share-based payments granted in the future. However, had we adopted Statement No. 123R in prior periods, the impact of that standard would have approximated the impact of Statement No. 123 as described in the disclosure of pro forma net income and earnings per share under Stock Based Compensation. We are still evaluating the effect of adopting this standard, but do not believe the Cumulative Effect of Change in Accounting Principle will be material to our results of operations.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections: a replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires voluntary changes in accounting principles to be applied retrospectively, unless it is impracticable. SFAS No. 154 s retrospective application requirement replaces APB 20 s requirement to recognize most voluntary changes in accounting principle by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. If retrospective application for all prior periods is impracticable, the method used to report the change and the reason the retrospective application is impracticable are to be disclosed.

Under SFAS No. 154, retrospective application will be the transition method in the unusual instance that a newly issued accounting pronouncement does not provide specific transition guidance. It is expected that many pronouncements will specify transition methods other than retrospective. SFAS No. 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005, and the adoption of this statement is expected to have no impact on our financial position or results of operations.

In July 2005, the FASB issued an exposure draft Accounting for Uncertain Tax Positions, a proposed interpretation of FASB Statement No. 109. The proposed interpretation would apply to all open tax positions under FASB No. 109. The conclusions in this interpretation include: initial recognition of tax benefits, recognition and de-recognition of tax positions, measurement of tax benefits and classifications of tax liabilities. The comment period on this exposure draft ended in September 2005, and we are currently assessing the impact, if any, that this interpretation would have on our financial position and results of operations. The FASB has not issued an effective date for this interpretation, and a final standard will likely be issued in 2006.

Proved Oil and Gas Reserves.

At year-end 2005, our total proved reserves were 761.8 Bcfe with a PV-10 Value of $3.2 billion (PV-10 is a non-GAAP measure, see the section titled Oil and Natural Gas Reserves in our Business and Properties section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). In 2005, our proved natural gas reserves decreased 30.8 Bcf, or 10%, while our proved oil reserves decreased 0.7 MMBbl, or 1%, and our NGL reserves decreased 0.5 MMBbl, or 3%, for a total equivalent decrease of 38.1 Bcfe, or 5%. In 2004, our proved natural gas reserves decreased by 17.6 Bcf, or 5%, while our proved oil reserves increased by 1.8 MMBbl, or 3%, and our NGL reserves decreased by 2.3 MMBbl, or 14%, for a total equivalent decrease of 20.5 Bcfe, or 3%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 31.6 Bcfe (2.0 of which came from New Zealand) of proved reserves in 2005, 7.2 Bcfe (all of which was domestic) in 2004, and 105.6 Bcfe (36.1 Bcfe of which came from New Zealand) in 2003. Through acquisitions we added 28.9 Bcfe of proved reserves in 2005, 43.4 Bcfe in 2004, and 0.5 Bcfe in 2003. At year-end 2005, 50% of our total proved reserves were proved developed, compared with 56% at year-end 2004 and 59% at year-end 2003.

The PV-10 Value of our total proved reserves at year-end 2005 increased 57% from the PV-10 Value at year-end 2004. Gas prices increased in 2005 to $8.94 per Mcf from $5.16 per Mcf at year-end 2004, compared to $4.56 per Mcf at year-end 2003. Oil prices increased in 2005 to $60.12 per Bbl from $41.07 per Bbl at year-end 2004,

compared to $30.16 in 2003. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant for that year s reserve calculation throughout the life of the properties. Subsequent changes to such year-end oil and gas prices could have a significant impact on the calculated PV-10 Value.

Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 1 to the consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage and business interruption claims,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the full-cost method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2005, 2004, and 2003, such internal costs capitalized totaled $18.8 million, $13.1 million, and $11.5 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2005, 2004, and 2003, capitalized interest on unproved properties totaled $7.2 million, $6.5 million, and $6.8 million, respectively. Interest not capitalized and general and administrative costs related to production and general overhead are expensed as incurred.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties (including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects (Ceiling Test). Our hedges at December 31, 2005 consisted of natural gas price floors with strike prices lower than the period-end price and thus did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

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The calculation of the Ceiling Test and provision for DD&A is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. Our reserves estimates are prepared in accordance with Securities and Exchange Commission guidelines; and, are audited on an annual basis at year-end by a firm of independent petroleum engineers in accordance with standards approved by the Board of Directors of the Society of Petroleum Engineers.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2005, 2004 and 2003, we recognized net losses of $1.1 million, $1.3 million and $2.8 million, respectively, relating to our derivative activities. This activity is recorded in Price-risk management and other, net on the accompanying statements of income. At December 31, 2005, the Company had recorded $0.1 million, net of taxes of less than $0.1 million, of derivative losses in Accumulated other comprehensive income (loss), net of income tax on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in Price-risk management and other, net for 2005, 2004, and 2003 was not material. We expect to reclassify all amounts currently held in Accumulated other comprehensive income (loss), net of income tax into the statement of income within the next six months when the forecasted sale of hedged production occurs.

At December 31, 2005, we had in place price floors in effect for February 2006 through the June 2006 contract month for natural gas, that cover a portion of our domestic natural gas production for February 2006 to June 2006. The natural gas price floors cover notional volumes of 2,075,000 MMBtu, with a weighted average floor price of $8.39 per MMBtu. Our natural gas price floors in place at December 31, 2005 are expected to cover approximately 35% to 40% of our estimated domestic natural gas production from February 2006 to June 2006.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in Accumulated other comprehensive income (loss), net of income tax. When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from Accumulated other comprehensive income (loss), net of income tax and recorded in Price-risk management and other, net on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes option pricing model and is periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2005, was $0.3 million and is recognized on the accompanying balance sheet in Other current assets.

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional discussion of commodity risk.

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Stock Based Compensation. We have three stock-based compensation plans, which are described more fully in Note 6 to our accompanying consolidated financial statements. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. We issued restricted stock for the first time in 2004 and again in 2005, and recorded expense related to these shares of $1.2 million and less than $0.1 million for 2005 and 2004, respectively, in General and administrative, net on the accompanying statements of income. No stock-based employee compensation cost is reflected in net income for employee stock options, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant.

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities cash flows, commodity pricing, environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, the New Zealand Deferred income taxes and a portion of our Asset Retirement Obligation on the accompanying balance sheet. For accounts other than Deferred income taxes, as the currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in Price-risk management and other, net on the accompanying statements of income. We recognize transaction gains and losses on Deferred income taxes in Provision for Income Taxes on the accompanying statement of income.

Related-Party Transactions

We are the operator of a number of properties owned by affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships totaled approximately $0.2 million in 2005, 2004 and 2003, and are recorded as reductions of general and administrative, net. We also have been reimbursed for administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled less than $0.1 million, $0.2 million, and $0.4 million in 2005, 2004, and 2003, respectively, and are recorded as reductions in general and administrative, net. Included in Accounts receivable and Accounts payable and accrued liabilities on the accompanying balance sheets, is approximately $0.4 million and $0.5 million, respectively, in receivables from and payables to the partnerships at December 31, 2005.

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the sister of the Company s Chairman of the Board and aunt of the Company s Chief Executive Officer. In 2005, 2004 and 2003, we paid approximately $0.4 million per year to Tec-Com for such services pursuant to the terms of the contract between the parties. The contract was renewed June 30, 2004 on substantially the same terms and expires June 30, 2007. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee s charter.

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Forward-Looking Statements

The statements contained in this report that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended. Such forward-looking statements may pertain to, among other things, financial results, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, and competition. Such forward-looking statements generally are accompanied by words such as plan, future, estimate, expect, budget, predict, anticipate, projected, should, believe, or other words that convey the uncertainty o events or outcomes. Such forward-looking information is based upon management s current plans, expectations, estimates, and assumptions, upon current market conditions, and upon engineering and geologic information available at this time, and is subject to change and to a number of risks and uncertainties, and, therefore, actual results may differ materially. Among the factors that could cause actual results to differ materially are: volatility in oil and natural gas prices, internationally or in the United States; availability of services and supplies; disruption of operations and damages due to hurricanes or tropical storms; fluctuations of the prices received or demand for our oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for capital; general economic conditions; changes in geologic or engineering information; changes in market conditions; competition and government regulations; as well as the risks and uncertainties discussed in this report and set forth from time to time in our other public reports, filings, and public statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility are expected to continue.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. Below is a description of the financial instruments we have utilized to hedge our exposure to price risk.

Price Floors At December 31, 2005, we had in place price floors in effect through the June 2006 contract month for natural gas, these cover a portion of our domestic natural gas production for February 2006 to June 2006. The natural gas price floors cover notional volumes of 2,075,000 MMBtu, with a weighted average floor price of $8.39 per MMBtu. Our natural gas price floors in place at December 31, 2005 are expected to cover approximately 35% to 40% of our domestic natural gas production from February 2006 to June 2006. The fair value of these instruments at December 31, 2005, was $0.3 million and is recognized on the accompanying balance sheet in Other current assets. There are no additional cash outflows for these price floors, as the cash premium was paid at inception of the hedge. The maximum loss that could be sustained from these price floors in 2006 would be their fair value at December 31, 2005 of $0.3 million.

New Zealand Gas Contracts All of our gas production in New Zealand is sold under long-term, fixed-price contracts denominated in New Zealand Dollars. These contracts protect against price volatility, and our revenue from these contracts will vary only due to production fluctuations and foreign exchange rates.

Interest Rate Risk. Our senior notes and senior subordinated notes both have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At December 31, 2005, we had no outstanding borrowings under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank s base rate would constitute 73 basis points and would not have a material adverse effect on our 2006 cash flows based on this same level or a modest level of borrowing.

Income Tax Carryforwards. We had significant federal and state net operating loss and capital loss carryforwards at December 31, 2005. The Company has not recorded a valuation allowance against the deferred tax assets attributable to these carryovers at December 31, 2005, as management estimates that it is more likely than not that these assets will be fully utilized before they expire except for a $0.5 million valuation allowance against the capital loss carryforward, as detailed in Note 3 of the accompanying consolidated financial statements. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company s ability to utilize the carryover amounts. If we are not able to use our carryforwards, our results of operations and cash flows will be negatively impacted.

Financial Instruments and Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2005 and 2004, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2005 and 2004, the fair values of our senior subordinated notes due 2012 were $214.5 million, or 107.25% of face value, and $224.0 million, or 112% of face value, respectively. Based upon quoted market prices as of December 31, 2005 and 2004, the fair values of our senior notes due 2011 were $153.8 million, or 102.5% of face value, and $162.4 million, or 108.25% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2005 and 2004. The carrying value of our senior notes due 2011 was $150.0 million at December 31 for both 2005 and 2004.

Foreign Currency Risk. We are exposed to the risk of fluctuations in foreign currencies, most notably the New Zealand Dollar. Fluctuations in rates between the New Zealand Dollar and U.S. Dollar may impact our

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financial results from our New Zealand subsidiaries since we have receivables, liabilities, natural gas and NGL sales contracts, and New Zealand income tax calculations, all denominated in New Zealand Dollars. We use the U.S. Dollar as our functional currency in New Zealand and because of this, our results of operations, cash flows and effective tax rate are impacted from fluctuations between the U.S. Dollar and the New Zealand Dollar.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and seek to minimize exposure to any one customer where other customers are readily available. Due to availability of other purchasers, we do not believe the loss of any single oil or gas customer would have a material adverse effect on our results of operations.

Item 8. Financial Statements and Supplementary Data page

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Management s Report on Internal Control over Financial Reporting

Management of Swift Energy Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company s internal control over financial reporting is a process designed by, or under the supervision of, the Company s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company s financial statements for external purposes in accordance with U. S. generally accepted accounting principles.

Management of the Company assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2005. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control Integrated Framework. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2005.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management s assessment of the Company s internal control over financial reporting as of December 31, 2005. That report, which expresses unqualified opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting as of December 31, 2005, appears on the following page.

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Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of Swift Energy Company

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that Swift Energy Company maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Swift Energy Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the company s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Swift Energy Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Swift Energy Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2005 and our report dated February 27, 2006 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 27, 2006

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Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 2005 and 2004, and the related consolidated statements of income, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2005 and 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Swift Energy Company s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2006 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 27, 2006

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Consolidated Balance Sheets
Swift Energy Company and Subsidiaries

	December 31, 2005	December 31, 2004
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 53,004,562	$ 4,920,118
Accounts receivable		
Oil and gas sales	45,518,260	38,021,693
Joint interest owners	1,082,187	960,395
Other Receivables	3,795,080	61,259
Other current assets	11,655,046	10,422,531
Total Current Assets	115,055,135	54,385,996
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,731,866,298	1,479,681,903
Unproved properties	87,553,220	80,121,509
	1,819,419,518	1,559,803,412
Furniture, fixtures, and other equipment	15,313,277	12,820,622
	1,834,732,795	1,572,624,034
Less Accumulated depreciation, depletion, and amortization	(755,699,056)	(649,185,874)
	1,079,033,739	923,438,160
Other Assets:		
Deferred income taxes		1,666,058
Debt issuance costs	8,026,780	9,148,977
Restricted assets	2,296,968	1,933,956
	10,323,748	12,748,991
	$ 1,204,412,622	$ 990,573,147
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 51,973,004	$ 29,406,877
Accrued capital costs	30,073,728	22,489,467
Accrued interest	8,508,196	9,209,192
Undistributed oil and gas revenues	7,866,086	7,512,755
Total Current Liabilities	98,421,014	68,618,291

Long-Term Debt	350,000,000	357,500,000
Deferred Income Taxes	129,306,891	73,106,580
Asset Retirement Obligation	19,095,368	17,176,136
Lease Incentive Obligation	271,182	
Commitments and Contingencies		
Stockholders Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding		
Common stock, $.01 par value, 85,000,000 shares authorized, 29,458,974 and 28,570,632 shares issued, and 29,009,530 and 28,089,764 shares outstanding, respectively	294,590	285,706
Additional paid-in capital	365,085,695	343,536,298
Treasury stock held, at cost, 449,444 and 480,868 shares, respectively	(6,445,586)	(6,896,245)
Unearned compensation	(5,849,820)	(1,728,585)
Retained earnings	254,302,757	138,524,301
Accumulated other comprehensive income (loss), net of income tax	(69,469)	450,665
	607,318,167	474,172,140
	$ 1,204,412,622	$ 990,573,147

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Income
Swift Energy Company and Subsidiaries

	Year Ended December 31,		
	2005	2004	2003
Revenues:			
Oil and gas sales	$ 423,766,245	$ 311,285,172	$ 211,032,639
Price-risk management and other, net	(539,756)	(1,008,398)	(2,131,656)
	423,226,489	310,276,774	208,900,983
Costs and Expenses:			
General and administrative, net	22,176,362	17,787,125	14,097,066
Depreciation, depletion, and amortization	107,477,787	81,580,828	63,072,057
Accretion of asset retirement obligation	761,042	673,654	857,356
Lease operating cost	47,321,841	41,214,256	33,833,198
Severance and other taxes	42,176,505	30,401,293	19,033,604
Interest expense, net	24,873,401	27,643,108	27,268,524
Debt retirement cost		9,536,268	
	244,786,938	208,836,532	158,161,805
Income Before Income Taxes and Change in Accounting Principle	178,439,551	101,440,242	50,739,178
Provision for Income Taxes	62,661,095	32,989,325	16,468,514
Income Before Change in Accounting Principle	$ 115,778,456	$ 68,450,917	$ 34,270,664
Cumulative Effect of Change in Accounting Principle (net of taxes)			4,376,852
Net Income	$ 115,778,456	$ 68,450,917	$ 29,893,812
Per Share Amounts			
Basic: Income Before Change in Accounting Principle	$ 4.06	$ 2.46	$ 1.25
Change in Accounting Principle			(0.16)
Net Income	$ 4.06	$ 2.46	$ 1.09
Diluted: Income Before Change in Accounting Principle	$ 3.95	$ 2.41	$ 1.24
Change in Accounting Principle			(0.16)

Net Income	$ 3.95	$ 2.41	$ 1.08
Weighted Average Shares Outstanding	28,496,275	27,822,413	27,357,579

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Stockholders Equity
Swift Energy Company and Subsidiaries

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Unearned Compensation	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2002	$ 278,116	$ 333,543,471	$ (8,749,922)	$	$ 40,179,572	$ (178,053)	$ 365,073,184
Stock issued for benefit plans (83,201 shares)	1	(408,178)	1,191,829				783,652
Stock options exercised (142,807 shares)	1,428	1,158,984					1,160,412
Tax benefits from exercise of stock options		156,980					156,980
Employee stock purchase plan (56,574 shares)	566	413,947					414,513
Comprehensive income:							
Net income					29,893,812		29,893,812
Change in fair value of cash flow hedges, net of income tax						(91,289)	(91,289)
Total comprehensive income							29,802,523
Balance, December 31, 2003	$ 280,111	$ 334,865,204	$ (7,558,093)	$	$ 70,073,384	$ (269,342)	$ 397,391,264
Stock issued for benefit plans (46,150 shares)		166,298	661,848				828,146
Stock options exercised (509,105	5,091	4,260,882					4,265,973

shares)							
Tax benefits from exercise of stock options		1,956,555					1,956,555
Employee stock purchase plan (50,418 shares)	504	502,097					502,601
Grants of restricted stock (100,900 shares)		1,785,262		(1,785,262)			
Amortization of restricted stock compensation				56,677			56,677
Comprehensive income:							
Net income					68,450,917		68,450,917
Change in fair value of cash flow hedges, net of income tax						720,007	720,007
Total comprehensive income							69,170,924
Balance, December 31, 2004	$ 285,706	$ 343,536,298	$ (6,896,245)	$ (1,728,585)	$ 138,524,301	$ 450,665	$ 474,172,140
Stock issued for benefit plans (31,424 shares)		435,134	450,659				885,793
Stock options exercised (840,847 shares)	8,409	9,804,555					9,812,964
Tax benefits from exercise of stock options		4,366,236					4,366,236
Employee stock purchase plan (32,495 shares)	325	642,354					642,679
Issuance of restricted stock (15,000 shares)	150						150
Grants of restricted stock (158,500		6,668,608		(6,072,008)			596,600

shares)							
Forfeitures of restricted stock		(367,490)		367,490			
Amortization of restricted stock compensation				1,583,283			1,583,283
Comprehensive income:							
Net income					115,778,456		115,778,456
Change in fair value of cash flow hedges, net of income tax						(520,134)	(520,134)
Total comprehensive income							115,258,322
Balance, December 31, 2005	$ 294,590	$ 365,085,695	$ (6,445,586)	$ (5,849,820)	$ 254,302,757	$ (69,469)	$ 607,318,167

(1)$.01 par value.

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2005	2004	2003
Cash Flows from Operating Activities:			
Net income	$ 115,778,456	$ 68,450,917	$ 29,893,812
Adjustments to reconcile net income to net cash provided by operating activities			
Cumulative effect of change in accounting principle			4,376,852
Depreciation, depletion, and amortization	107,477,787	81,580,828	63,072,057
Accretion of asset retirement obligation	761,042	673,654	857,356
Deferred income taxes	61,911,095	32,513,325	16,332,492
Debt retirement cost cash and non-cash		9,536,268	
Other	1,812,613	(435,439)	908,927
Change in assets and liabilities-			
Increase in accounts receivable	(6,778,383)	(11,040,543)	(7,163,304)
Increase in accounts payable and accrued liabilities	5,071,870	843,341	2,432,111
Increase (decrease) in accrued interest	(700,996)	460,536	116,976
Net Cash Provided by Operating Activities	285,333,484	182,582,887	110,827,279
Cash Flows from Investing Activities:			
Additions to property and equipment	(235,547,815)	(171,095,101)	(144,503,180)
Proceeds from the sale of property and equipment	7,296,833	5,058,147	10,186,970
Acquisition of South Bearhead Creek fields	(28,927,091)		
Acquisition of Bay de Chene and Cote Blanche Island fields		(27,196,336)	
Net cash received as operator of oil and gas properties	17,797,022	3,921,673	3,073,718
Net cash received (distributed) as operator of partnerships	(948,292)	884,093	260,726
Other	255,189	(658,630)	(71,193)
Net Cash Used in Investing Activities	(240,074,154)	(189,086,154)	(131,052,959)
Cash Flows from Financing Activities:			
Proceeds from long-term debt		150,000,000	
Payments of long-term debt		(125,000,000)	
Net proceeds from (payments of) bank borrowings	(7,500,000)	(8,400,000)	15,900,000
Net proceeds from issuances of common stock	10,325,114	4,825,251	1,575,853
Payments of debt retirement costs		(6,734,611)	
Payments of debt issuance costs		(4,333,535)	
Net Cash Provided by Financing Activities	2,825,114	10,357,105	17,475,853
Net Increase (Decrease) in Cash and Cash Equivalents	$ 48,084,444	$ 3,853,838	$ (2,749,827)

Cash and Cash Equivalents at Beginning of Year	4,920,118	1,066,280	3,816,107
Cash and Cash Equivalents at End of Year	$ 53,004,562	$ 4,920,118	$ 1,066,280
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 24,482,934	$ 26,064,158	$ 25,763,169
Cash paid during year for income taxes	$ 750,000	$ 476,000	$ 129,738

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements
Swift Energy Company and Subsidiaries

1. Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying consolidated financial statements include the accounts of Swift Energy Company and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas, as well as onshore oil and natural gas reserves in New Zealand. Our undivided interests in gas processing plants, and investments in oil and gas limited partnerships where we are the general partner are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity s assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying consolidated financial statements.

Holding Company Structure. In December 2005, we implemented a holding company structure pursuant to Texas and federal law in a manner designed to be a non-taxable transaction. The new parent holding company assumed the Swift Energy Company name and its common stock and continued to trade on the New York and Pacific Stock Exchanges. The purposes of this new holding company structure are to separate Swift Energy s domestic and international operations to better reflect management practices, to improve our economics, and to provide greater administrative and organizational flexibility. Under the new organizational structure, four new subsidiaries were formed with the Texas parent holding company wholly owning three Delaware subsidiaries, which in turn wholly own Swift Energy s operating subsidiaries. Swift Energy Operating, LLC is the operator of record for Swift Energy s domestic properties. Swift Energy s name, charter, bylaws, officers, board of directors, authorized shares and shares outstanding remain substantially identical. The Company s international operations continue to be conducted through Swift Energy International, Inc. Swift Energy made amendments to its bank credit agreement, debt indentures and various other plans and documents to accommodate the internal reorganization, but the Company s day-to-day conduct of business was not impacted. Accordingly, there was no impact on our financial position or results of operations.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States (GAAP) requires us to make estimates and assumptions that affect the reported amount of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- accruals related to oil and gas revenues, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage,
- the estimated future cost and timing of asset retirement obligations, and
- estimates made in our income tax calculations.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustment occurs.

Property and Equipment. We follow the full-cost method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and gas reserves are capitalized. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the years 2005, 2004, and 2003, such internal costs capitalized totaled $18.8 million, $13.1 million, and $11.5 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2005, 2004, and 2003, capitalized interest on unproved properties totaled $7.2 million, $6.5 million, and $6.8 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and gas property costs are amortized.

We compute the provision for depreciation, depletion, and amortization (DD&A) of oil and gas properties by the unit-of-production method. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves at the beginning of the period. This calculation is done on a country-by-country basis, and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment, recorded at cost, are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between three and 20 years. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

Geological and geophysical (G&G) costs incurred on developed properties are recorded in Proved properties and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in Unproved properties and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulate in countries where there are no proved reserves, any costs determined by management to be impaired are charged to expense.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and gas properties (including gas processing facilities, capitalized asset retirement obligations, net of related salvage values and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using period-end prices, adjusted for the effects of hedging, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects (Ceiling Test). Our hedges at December 31, 2005 consisted of natural gas price floors with strike prices lower than the period-end price and thus did not materially affect prices used in this calculation. This calculation is done on a country-by-country basis.

The calculation of the Ceiling Test and provision for DD&A is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. Our reserves estimates are prepared in accordance with Securities and Exchange Commission guidelines; and, are audited on an annual basis at year-end by a firm of independent petroleum engineers in accordance with standards approved by the Board of Directors of the Society of Petroleum Engineers.

Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline from our period-end prices used in the Ceiling Test, even if only for a short period, it is possible that non-cash write-downs of oil and gas properties could occur in the future.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectibility of the revenue is probable. Processing costs for natural gas and natural gas liquids (NGLs) that are paid in-kind are deducted from revenues. The Company uses the entitlement method of accounting in which the Company recognizes its ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in Accounts payable and accrued liabilities on the accompanying balance sheet. Natural gas balancing receivables are reported in Other current assets on the accompanying balance sheet when our ownership share of production exceeds sales. As of December 31, 2005, we did not have any material natural gas imbalances.

Accounts Receivable. Included in the Accounts receivable balance, which totaled $39.0 million at December 31, 2004, on the accompanying balance sheets, were approximately $2.3 million of receivables related to hydrocarbon volumes produced from 2001 and 2002 that had been disputed since early 2003. As a result of the dispute, we did not record a receivable with regard to any 2003 disputed volumes and our contract governing these sales expired in 2003. Based on settlement discussions, we settled our claim with this counter-party in July 2005 by receiving a cash payment for less than our gross receivable. Accordingly, in the second quarter of 2005, we increased our reserve for this claim by approximately $0.6 million, which is recorded in Price-risk management and other, net on the accompanying statements of income.

We assess the collectibility of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At December 31, 2005 and 2004, we had an allowance for doubtful accounts of less than $0.1 million and $0.5 million, respectively. The allowance for doubtful accounts has been deducted from the total Accounts receivable balances on the accompanying balance sheets.

Debt Issuance Costs. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the public offering in April 2002 of our 9-3/8% senior subordinated notes due 2012, the June 2004 extension of our bank credit facility, and the public offering in June 2004 of our 7-5/8% senior notes due 2011 were capitalized and are amortized on an effective interest basis over the life of each of the respective note offerings and credit facility. The 9-3/8% senior subordinated notes due 2012 mature on May 1, 2012, and the balance of their issuance costs at December 31, 2005, was $4.1 million, net of accumulated amortization of $1.5 million. The issuance costs associated with our revolving credit facility, which was extended in June 2004, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2005, was $0.6 million, net of accumulated amortization of $1.8 million. The 7-5/8% senior notes due 2011 mature on July 15, 2011, and the balance of their issuance costs at December 31, 2005, was $3.3 million, net of accumulated amortization of $0.7 million.

Limited Partnerships. At year-end 2005, we serve as managing general partner for two private limited partnerships, and during fiscal 2005, less than 1% of our total oil and gas sales was attributable to our general and limited partner interests in those partnerships. These two partnerships were formed between 1996 and 1998, and will continue to operate until their limited partners vote otherwise.

Price-Risk Management Activities. The Company follows SFAS No. 133, which requires that changes in the derivative s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The statement also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the balance sheet as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

We have a price-risk management policy to use derivative instruments to protect against declines in oil and gas prices, mainly through the purchase of price floors and collars. During 2005, 2004 and 2003, we recognized net losses of $1.1 million, $1.3 million and $2.8 million, respectively, relating to our derivative activities. This activity is recorded in Price-risk management and other, net on the accompanying statements of income. At December 31, 2005, the Company had recorded $0.1 million, net of taxes of less than $0.1 million, of derivative losses in Accumulated other comprehensive income (loss), net of income tax on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our hedging transactions that qualified as cash flow hedges. The ineffectiveness reported in Price-risk management and other, net for 2005, 2004, and 2003 was not material. We expect to reclassify all amounts currently held in Accumulated other comprehensive income (loss), net of income tax into the statement of income within the next six months when the forecasted sale of hedged production occurs.

At December 31, 2005, we had in place price floors in effect for February 2006 through the June 2006 contract month for natural gas, that cover a portion of our domestic natural gas production for February 2006 to June 2006. The natural gas price floors cover notional volumes of 2,075,000 MMBtu, with a weighted average floor price of $8.39 per MMBtu. Our natural gas price floors in place at December 31, 2005 are expected to cover approximately 35% to 40% of our estimated domestic natural gas production from February 2006 to June 2006.

When we entered into these transactions discussed above, they were designated as a hedge of the variability in cash flows associated with the forecasted sale of natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in Accumulated other comprehensive income (loss), net of income tax. When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are reclassified from Accumulated other comprehensive income (loss), net of income tax and recorded in Price-risk management and other, net on the accompanying statement of income. The fair value of our derivatives is computed using the Black-Scholes-Merton option pricing model and is periodically verified against quotes from brokers. The fair value of these instruments at December 31, 2005, was $0.3 million and is recognized on the accompanying balance sheet in Other current assets.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to general and administrative, net based on our estimate of the costs incurred to operate the wells, with the remainder applied as a reduction to lease operating cost. Based on recent estimates, effective October 1, 2003, we began recording the supervision fee only as a reduction to general and administrative, net. The total amount of supervision fees charged to the wells we operate was $7.8 million in 2005, $5.8 million in 2004, and $5.1 million in 2003.

Inventories. We value inventories at the lower of cost or market value. Cost of crude oil inventory is determined using the weighted average method and all other inventory is accounted for using the first in, first out method (FIFO). The major categories of inventories, which are included in Other current assets on the accompanying balance sheets, are shown as follows:

	Balance at December 31, 2005 (000 s)	Balance at December 31, 2004 (000 s)
Materials, Supplies and Tubulars	$ 8,494	$ 6,417
Crude Oil	916	770
Total	$ 9,410	$ 7,187

Income Taxes. Under SFAS No. 109, Accounting for Income Taxes, deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws. The effective tax rate for 2005, 2004 and 2003 was lower than the statutory tax rates primarily due to reductions from the New Zealand statutory rate attributable to the currency effect on the New

Zealand deferred tax calculation. The provision for 2005 included the reversal of a New Zealand repatriation allowance offset by an adjustment to correct an immaterial error in a prior year s tax returns and higher state tax rate estimates. The effective tax rate for 2004 included favorable corrections to

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tax basis amounts discovered while preparing the prior year s tax returns, partially offset by higher deferred state income taxes. Income tax expense in 2003 included higher domestic state income taxes and other items. The tax laws in the jurisdictions we operate in are continuously changing and professional judgments regarding such laws can differ.

Accounts Payable and Accrued Liabilities. Included in Accounts payable and accrued liabilities, on the accompanying balance sheets, at December 31, 2005 and 2004 are liabilities of approximately $9.9 million and $6.9 million, respectively, which represent the amounts by which checks issued, but not presented to the Company s banks for collection, exceeded balances in the applicable bank accounts.

Cash and Cash Equivalents. We consider all highly liquid debt instruments with an initial maturity of three months or less to be cash equivalents.

Credit Risk Due to Certain Concentrations. We extend credit, primarily in the form of uncollateralized oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions within our industry and may accordingly impact our overall credit risk. However, we believe that the risk of these unsecured receivables is mitigated by the size, reputation, and nature of the companies to which we extend credit. During 2005, oil and gas sales to Shell Oil and affiliates, both domestically and in New Zealand, were $179.9 million, or 42% of total oil and gas sales. During 2004, oil and gas sales to Shell Oil and affiliates, both domestically and in New Zealand, were $149.2 million, or 48% of total oil and gas sales. During 2003, oil and gas sales to Shell Oil and affiliates, both domestically and in New Zealand, were $31.1 million, or 15% of total oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were $23.5 million, or 11% of total oil and gas sales. Credit losses in 2005, 2004 and 2003 have been immaterial.

Environmental Costs. Our operations include activities that are subject to extensive federal and state environmental regulations. Costs associated with redemption projects, which are probable and reasonably estimable, are accrued in advance. Ongoing environmental compliance costs are expensed as incurred.

Restricted Assets. These balances primarily include amounts deposited on plugging bonds in New Zealand, along with amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. These amounts are restricted as to their current use, and will be released when we have satisfied all plugging and abandonment obligations in certain fields domestically and in New Zealand.

Foreign Currency. We use the U.S. Dollar as our functional currency in New Zealand. The functional currency is determined by examining the entities cash flows, commodity pricing environment and financing arrangements. We have both assets and liabilities denominated in New Zealand Dollars, the New Zealand Deferred income taxes and a portion of our Asset Retirement Obligation on the accompanying balance sheet. For accounts other than Deferred income taxes, as the currency rate changes between the U.S. Dollar and the New Zealand Dollar, we recognize transaction gains and losses in Price-risk management and other, net on the accompanying statements of income. We recognize transaction gains and losses on Deferred income taxes in Provision for Income Taxes on the accompanying statement of income.

Fair Value of Financial Instruments. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2005 and 2004, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based upon quoted market prices as of December 31, 2005 and 2004, the fair values of our senior subordinated notes due 2012 were $214.5 million, or 107.25% of face value, and $224.0 million, or 112% of face value, respectively. Based upon quoted market prices as of December 31, 2005 and 2004, the fair values of our senior notes due 2011 were $153.8 million, or 102.5% of face value, and $162.4 million, or 108.25% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2005 and 2004. The carrying value of our senior notes due 2011 was $150.0 million at December 31, 2005.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current year presentation.

Accumulated Other Comprehensive Income (Loss), Net of Income Tax. We follow the provisions of SFAS No. 130, Reporting Comprehensive Income, which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At December 31, 2005, we recorded $0.1 million, net of taxes of less than $0.1 million, of derivative losses in Accumulated other comprehensive income (loss), net of income tax on the accompanying balance sheet. The components of accumulated other comprehensive Income (loss) and related tax effects for 2005 were as follows:

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive income at December 31, 2004	$ 710,828	$ (260,163)	$ 450,665
Change in fair value of cash flow hedges	203,135	(74,957)	128,178
Effect of cash flow hedges settled during the period	(1,024,057)	375,745	(648,312)
Other comprehensive loss at December 31, 2005	$ (110,094)	$ 40,625	$ (69,469)

Total comprehensive income was $115.3 million, $69.2 million, and $29.8 million for 2005, 2004, and 2003, respectively.

Stock Based Compensation. We have two stock-based compensation plans, which are described more fully in Note 6. We account for those plans under the recognition and measurement principles of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. We issued restricted stock to employees for the first time in 2004 and again in 2005, and recorded expense related to restricted stock shares of less than $0.1 million and $1.2 million in General and administrative, net on the accompanying statements of income in 2004 and 2005, respectively. No stock-based employee compensation cost is reflected in net income for employee stock options, as all options granted under those plans had an exercise price equal to the fair market value of the underlying common stock on the date of the grant; or in the case of the employee stock purchase plan, the purchase price is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Had compensation expense for these plans been determined based on the fair value of the options consistent with SFAS No. 123, Accounting for Stock-Based Compensation, our net income and earnings per share would have been adjusted to the following pro forma amounts:

		2005	**2004**	**2003**
Net Income:	As Reported	$ 115,778,456	$ 68,450,917	$ 29,893,812
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(2,712,441)	(3,557,541)	(4,112,455)
	Pro Forma	$ 113,066,015	$ 64,893,376	$ 25,781,357
Basic EPS:	As Reported	$ 4.06	$ 2.46	$ 1.09
	Pro Forma	$ 3.97	$ 2.33	$ 0.94
Diluted EPS:	As Reported	$ 3.95	$ 2.41	$ 1.08
	Pro Forma	$ 3.86	$ 2.29	$ 0.94

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years. The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes-Merton option-pricing model with the following weighted average assumptions in 2005, 2004, and 2003, respectively: no dividend yield; expected volatility factors of 41.6%, 38.6%, and 34.71%; risk-free interest rates of 3.83%, 3.59%, and 4.63%; and expected lives of 3.9, 5.4, and 7.2 years. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

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Asset Retirement Obligation. In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, Accounting for Asset Retirement Obligations. The statement requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the year the well is expected to deplete. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss. This standard requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. Based on our experience and analysis of the oil and gas services industry, we have not factored a market risk premium into our asset retirement obligation. SFAS No. 143 was adopted by us effective January 1, 2003. Upon adoption of SFAS No. 143, we recorded an asset retirement obligation of $8.9 million, an addition to oil and gas properties of $2.0 million, and a non-cash charge of $4.4 million (net of $2.5 million of deferred taxes), which is recorded as a Cumulative Effect of Change in Accounting Principle. The cumulative charge to earnings took into consideration the impact of adopting SFAS No. 143 on previous full-cost ceiling tests. SFAS No. 143 is silent with respect to whether prior period ceiling tests should be reflected in the implementation entry calculation; however, management believes that any impairment on the properties should be reflected in the historical periods. Had we not considered the impact of adopting SFAS No. 143 on previous full-cost ceiling tests, the charge recognized would have been reduced. Excluding the Cumulative Effect of Change in Accounting Principle, the adoption of SFAS No. 143 reduced our 2003 net income by approximately $0.6 million, or $0.02 per diluted share.

The following provides a roll-forward of our asset retirement obligation:

Asset Retirement Obligation recorded as of January 1, 2003	$ 8,934,320
Accretion expense for 2003	857,356
Liabilities incurred for new wells and facilities construction	608,166
Reductions due to sold and abandoned wells	(443,391)
Revisions in estimated cash flows	67,511
Increase due to currency exchange rate fluctuations	113,511
Asset Retirement Obligation recorded as of January 1, 2004	$ 10,137,473
Accretion expense for 2004	673,654
Liabilities incurred for new wells and facilities construction	712,521
Liabilities incurred for Bay de Chene and Cote Blanche Island acquisitions	2,941,490
Reductions due to sold and abandoned wells	(1,083,174)
Revisions in estimated cash flows	4,195,474
Increase due to currency exchange rate fluctuations	61,698
Asset Retirement Obligation as of December 31, 2004	$ 17,639,136
Accretion expense for 2005	761,041
Liabilities incurred for new wells and facilities construction	616,206
Liabilities incurred for South Bearhead Creek acquisitions	426,377
Reductions due to sold and abandoned wells	(464,519)
Revisions in estimated cash flows	416,861
Decrease due to currency exchange rate fluctuations	(38,735)
Asset Retirement Obligation as of December 31, 2005	$ 19,356,367

At December 31, 2005 and 2004, approximately $0.3 million and $0.5 million, respectively, of our asset retirement obligation is classified as a current liability in Accounts payable and accrued liabilities on the accompanying consolidated balance sheets.

New Accounting Pronouncements. EITF 04-05 addresses when a limited partnership should be consolidated by its general partner. EITF 04-05 presumes that a sole general partner in a limited partnership controls the limited partnership, and therefore should consolidate the limited partnership. The presumption of control can be overcome if the limited partners have (a) the substantive ability to remove the sole general partner or otherwise dissolve the limited partnership or (b) substantive participating rights. The EITF reached a tentative conclusion on the circumstances in which either kick-out rights or participating rights would be considered substantive and preclude consolidation by the general partner. The FASB ratified the EITF consensus at the June 2005 EITF meeting. We do not believe this EITF will have a material impact on our consolidated financial statements because we believe our limited partners have substantive kick-out rights under paragraph B20 of FIN 46R.

In December 2004, the FASB issued SFAS No. 123R, Share-Based Payment. SFAS No. 123R is a revision of SFAS No. 123, Accounting for Stock-Based Compensation, and supercedes APB Opinion No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. SFAS No. 123R requires all employee share-based payments, including grants of employee stock options, to be recognized in the financial statements based on their fair values. SFAS No. 123 discontinues the ability to account for these equity instruments under the intrinsic value method as described in APB Opinion No. 25. SFAS No. 123R requires the use of an option pricing model for estimating fair value, which is amortized to expense over the service periods. The requirements of SFAS No. 123R are effective for fiscal periods beginning after June 15, 2005. SFAS No. 123R permits public companies to adopt its requirements using one of two methods, we have chosen the modified prospective method in which compensation cost is recognized beginning with the effective date based on the requirements of SFAS No. 123R for all share-based payments granted after the effective date and based on the requirements of SFAS No. 123 for all awards granted to employees prior to the adoption date of SFAS No. 123R that remain unvested on the adoption date.

In April 2005, the SEC issued a release announcing that it would provide for a phased-in implementation process for SFAS No. 123R. As a result, our required date to adopt SFAS No. 123R is January 1, 2006. Also in April 2005, the SEC issued Staff Accounting Bulleting No. 107, Share-Based Payment, which provides guidance on the implementation of SFAS No. 123R. SAB No. 107 provides guidance on valuing options, estimating volatility and expected terms of the option awards, and discusses the SEC s views on share-based payment transactions with non-employees, the capitalization of compensation cost and accounting for income tax effects of share-based payment arrangements upon adoption of SFAS No. 123R.

We will adopt the provisions of SFAS No. 123R effective January 1, 2006 using the modified prospective method. As permitted by Statement 123, the Company previously accounted for share-based payments to employees using APB Opinion No. 25 s intrinsic value method and, as such, generally recognizes no compensation cost for employee stock options. Accordingly, the adoption of Statement No. 123R s fair value method is expected to have a significant impact on our results of operations. However, it will have no impact on our overall financial position. We use the Black-Scholes-Merton formula to estimate the value of stock options granted to employees and expect to continue to use this acceptable option valuation model after the required adoption of SFAS No. 123R. The significance of the impact of adoption will depend on levels of outstanding unvested share-based payments on the date of adoption and share-based payments granted in the future. However, had we adopted Statement No. 123R in prior periods, the impact of that standard would have approximated the impact of Statement No. 123 as described in the disclosure of pro forma net income and earnings per share under Stock Based Compensation. We are still evaluating the effect of adopting this standard, but do not believe the Cumulative Effect of Change in Accounting Principle will be material to our results of operations.

In May 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections: a replacement of APB Opinion No. 20 and FASB Statement No. 3. SFAS No. 154 requires voluntary changes in accounting principles to be applied retrospectively, unless it is impracticable. SFAS No. 154 s retrospective application requirement replaces APB 20 s requirement to recognize most voluntary changes in accounting principle by including in net income of the period of the change the cumulative effect of changing to the new accounting principle. If retrospective application for all prior periods is impracticable, the method used to report the change and the reason the retrospective application is impracticable are to be disclosed.

Under SFAS No. 154, retrospective application will be the transition method in the unusual instance that a newly issued accounting pronouncement does not provide specific transition guidance. It is expected that many pronouncements will specify transition methods other than retrospective. SFAS No. 154 is effective for accounting changes made in fiscal years beginning after December 15, 2005, and the adoption of this statement is expected to have no impact on our financial position or results of operations.

In July 2005, the FASB issued an exposure draft Accounting for Uncertain Tax Positions, a proposed interpretation of FASB Statement No. 109. The proposed interpretation would apply to all open tax positions under FASB No. 109.

The conclusions in this interpretation include: initial recognition of tax benefits, recognition and de-recognition of tax positions, measurement of tax benefits and classifications of tax liabilities. The comment period on this exposure draft ended in September 2005, and we are currently assessing the

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impact, if any, that this interpretation would have on our financial position and results of operations. The FASB has not issued an effective date for this interpretation, and a final standard will likely be issued in 2006.

2. Earnings Per Share

Basic earnings per share (Basic EPS) have been computed using the weighted average number of common shares outstanding during the respective periods. Diluted earnings per share (Diluted EPS) for all periods also assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Certain of our stock options and restricted stock that would potentially dilute Basic EPS in the future were also antidilutive for the 2005, 2004, and 2003 periods and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 2005, 2004, and 2003:

	2005			2004			2003		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:									
Net Income and Share Amounts	$ 115,778,456	28,496,275	$ 4.06	$ 68,450,917	27,822,413	$ 2.46	$ 29,893,812	27,357,579	$ 1.09
Dilutive Securities:									
Restricted Stock		61,516							
Stock Options		736,937			524,860			203,360	
Diluted EPS:									
Net Income and Assumed Share Conversions	$ 115,778,456	29,294,728	$ 3.95	$ 68,450,917	28,347,273	$ 2.41	$ 29,893,812	27,560,939	$ 1.08

Options to purchase approximately 2.1 million shares at an average exercise price of $21.28 were outstanding at December 31, 2005, while options to purchase 3.0 million shares at an average exercise price of $18.51 were outstanding at December 31, 2004, and options to purchase 3.2 million shares at an average exercise price of $16.37 were outstanding at December 31, 2003. Approximately 0.1 million, 1.1 million, and 1.7 million options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2005, 2004, and 2003, respectively, because these options were antidilutive in that the option price was greater than the average closing market price for the common shares during those periods. Employee restricted stock grants of 6,990 shares and 70,900 shares, were not included in the computation of Diluted EPS for the year ended December 31, 2005, and 2004, respectively, because these restricted stock grants were antidilutive in that the amount of future compensation expense per share recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during that period. Other restricted stock grants of 15,000 shares, which were issued in 2004, were not included in the computation of Diluted EPS for the year ended December 31, 2005, as performance conditions surrounding the vesting of these shares had not occurred.

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3. Provision for Income Taxes

Income before taxes is as follows:

	Year Ended December 31,		
	2005	**2004**	**2003**
United States	$ 155,862,846	$ 86,000,508	$ 38,955,405
Foreign	22,576,705	15,439,734	11,783,773
Total	$ 178,439,551	$ 101,440,242	$ 50,739,178

The following is an analysis of the consolidated income tax provision:

	Year Ended December 31,		
	2005	2004	2003
Current	$ 643,760	$ 469,717	$ 164,284
Deferred Domestic	57,605,580	31,137,643	14,386,868
Foreign	4,411,755	1,381,965	1,917,362
Total Deferred	62,017,335	32,519,608	16,304,230
Total	$ 62,661,095	$ 32,989,325	$ 16,468,514

Reconciliations of income taxes computed using the U.S. Federal statutory rate to the effective income tax rates are as follows:

	2005	**2004**	**2003**
Income taxes computed at U.S. statutory rate (35%)	$ 62,453,843	$ 35,504,086	$ 17,758,712
State tax provisions, net of federal benefits	2,145,164	1,140,499	373,992
Effect of foreign operations	(451,534)	(308,795)	(235,675)
Currency exchange impact on foreign tax calculation	(2,769,519)	(2,516,120)	(2,893,655)
Cumulative impact of adjustments to net state income tax rate	1,008,166	858,943	1,216,105
Other, net	274,975	(1,689,288)	249,035
Provision for income taxes	$ 62,661,095	$ 32,989,325	$ 16,468,514
Effective rate	35.1%	32.5%	32.5%

As noted in the above table, the most significant contributor to the difference between the federal statutory rate and the effective rate is the currency exchange impact on the foreign income tax calculation. The Company s New Zealand subsidiaries use the U.S. Dollar as their functional currency for financial reporting purposes, but income taxes are calculated from New Zealand Dollar financial statements and re-measured into U.S. Dollars. Volatility in exchange rates creates variable results when computing income in different currencies. The most significant difference in the relative income computations (computed using historical basis U.S. dollars versus historical basis New Zealand dollars) was attributable to depreciation, depletion, and amortization (DD&A). Because of the relative strengthening of the New Zealand Dollar vs. the U.S. Dollar, the value of the tax DD&A deduction reflects the relative appreciation in the New Zealand Dollar tax basis of amortizable assets vs. the historical U.S. Dollar investment costs. As a result, taxable income (and accordingly

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income tax expense) computed in New Zealand Dollars and then converted to U.S. Dollars at the average exchange rates for each respective year was significantly less than net income computed in the subsidiaries U.S. Dollar financial statements. In aggregate, the Company recognized foreign exchange benefits to tax expense in the amounts of $2.8 million, $2.5 million, and $2.9 million for 2005, 2004, and 2003, respectively.

The primary unfavorable differences between the federal statutory and the effective rate are attributable to state income taxes (computed net of the offsetting federal benefit), which were $2.1 million, $1.1 million and $0.4 million for 2005, 2004, and 2003, respectively. Additionally, the Company recorded adjustments to the cumulative state deferred tax liability in the amounts of $1.0 million, $0.9 million, and $1.2 million for 2005, 2004, and 2003, respectively. For 2005 the change is due to an increase in the portion of income the Company expects to be subject to Texas earned surplus tax. For 2004 and 2003 the increases are due to increases in the level of business activity in Louisiana. The Company calculates its Louisiana income tax using the apportionment accounting method. Under apportionment accounting, total federal taxable income is allocated based on the proportional level of U.S. business activity within the state. Due to the relative increases in the Company s Louisiana activity in 2003 and 2004, the Company increased its estimate of future Louisiana taxable income that will result from the reversal of prior years timing differences.

The New Zealand statutory rate is 33%, which resulted in differences of $0.5 million, $0.3 million, and $0.2 million for 2005, 2004, and 2003 respectively vs. the U.S. statutory rate. The Company does not compute a provision for U.S. taxes on the undistributed earnings of our New Zealand subsidiaries as management has plans to reinvest such earnings outside of the United States indefinitely. As of December 31, 2005, the undistributed earnings of foreign subsidiaries is approximately $47.4 million. If, in the future, these earnings are distributed into the U.S. in the form of dividends or otherwise, we may be subject to U.S. income taxes and New Zealand withholding taxes. It is not practical, however, to estimate the amount of taxes that may be payable if such remittances occur. Presently, there are no foreign tax credits available to reduce the U.S. taxes on such amounts if repatriated.

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2005 and 2004, were as follows:

	2005	2004
Deferred tax assets:		
Alternative minimum tax credits (Domestic)	$ (3,201,403)	$ (2,579,399)
Carryover items (Domestic)	(38,118,606)	(47,600,945)
Acquired deferred tax asset (Foreign)	(2,408,359)	(3,407,885)
Carryover Items (Foreign)	(46,089,010)	(37,852,559)
Other (Domestic)	(883,742)	(167,475)
Total deferred tax assets	$ (90,701,120)	$ (91,608,263)
Deferred tax liabilities		
Domestic oil and gas exploration and development costs	$ 167,087,634	$ 121,893,202
Foreign oil and gas exploration and development costs	51,863,230	39,594,386
Other (Domestic)	1,057,147	1,561,197
Total deferred tax liabilities	$ 220,008,011	$ 163,048,785
Net deferred tax liabilities	$ 129,306,891	$ 71,440,522

The total change in the net deferred liability from 2004 to 2005 was $57.9 million. Increases in the liability were attributable to deferred tax expense of $62.0 million plus $0.6 million for other adjustments. Reductions were made to the net liability for the tax benefit of stock compensation deductions of $4.4 million, which are recorded as additions to paid-in-capital, and $0.4 million for other items.

The tax basis of the assets of Southern Petroleum (NZ) Exploration Limited (Southern NZ) on the acquisition date exceeded the cash purchase price paid by SENZ to acquire this entity. The asset is being amortized over the period in which the tax amortization is deducted. The remaining asset value at December 31, 2005, was $2.4 million. The other foreign carryover asset is attributable to cumulative New Zealand net operating losses of $139.7 million. New Zealand tax net operating losses do not expire.

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At December 31, 2005, the Company had alternative minimum tax credits of $3.2 million that carry forward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the alternative minimum tax otherwise due.

The domestic deferred tax carryover items are attributable to expected future tax benefits in the amounts of $28.6 million for federal net operating losses, $2.4 million for State of Louisiana net operating losses and $7.1 million net for capital losses. The gross capital loss asset is $7.6 million less a $0.5 million impairment. At December 31, 2005, cumulative estimated federal net operating losses were $81.5 million, which will expire between 2019 and 2023. Louisiana estimated net operating losses total $69.2 million and will expire between 2013 and 2019.

The Company has not recorded any valuation allowance against the deferred tax assets attributable to net operating loss carryovers at December 31, 2005 and 2004, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company s ability to utilize the carryover amounts.

In 2002 we recognized a capital loss of approximately $18.6 million as the result of the liquidation of our partnerships. In 2005 we recognized an additional capital loss of $3.1 million for partnerships liquidated during the year. These losses can only be utilized to offset capital gains. The 2002 losses will expire in 2007, and the 2005 losses will expire in 2010. The Company plans to sell some combination of its oil and gas properties before the loss carryovers expire that will generate sufficient capital gains to utilize the loss carry over. To generate capital gains from these dispositions, the sales proceeds must exceed the Company s total investment in the properties. Company management has identified several qualified properties that have estimated current market values well in excess of the total original costs. Management believes that it is more likely than not that the Company will fully utilize the capital loss carryover. If the Company is unable to complete the sale of these properties at the prices it has estimated to be the fair market value, then a significant portion of the capital loss carryover could expire before it is utilized. During 2004 the Company recorded a valuation allowance of $0.5 million, primarily for incremental state income tax expenses that it expects to incur as a result of the planned property dispositions.

4. Long-Term Debt

Our long-term debt as of December 31, 2005 and 2004, is as follows:

	2005	**2004**
Bank Borrowings	$	$ 7,500,000
7-5/8% senior notes due 2011	150,000,000	150,000,000
9-3/8% senior subordinated notes due 2012	200,000,000	200,000,000
Long-Term Debt	$ 350,000,000	$ 357,500,000

Bank Borrowings. At December 31, 2005, we had no borrowings under our $400.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2008. At December 31, 2004, we had $7.5 million in outstanding borrowings under our credit facility. The interest rate is either (a) the lead bank s prime rate (7.25% at December 31, 2005) or (b) the adjusted London Interbank Offered Rate (LIBOR) plus the applicable margin depending on the level of outstanding debt. The applicable margin is based on the ratio of the outstanding balance to the last calculated borrowing base. In June 2004, we increased, renewed and extended this credit facility, increasing the facility to $400 million from $300 million and extending its expiration to October 1, 2008 from October 1, 2005. The other terms of the credit facility, such as the borrowing base amount and commitment amount, stayed largely the same. The covenants related to this credit facility changed somewhat with the extension of the facility and are discussed below. We incurred $0.4 million of debt issuance costs related to the renewal of this facility in 2004, which is included in Debt issuance costs on the accompanying consolidated balance sheets and will be amortized to interest expense over the life of the facility.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX), and limitations on incurring other debt or repurchasing our 7-5/8% senior notes due 2011 or 9-3/8% senior subordinated notes due 2012. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two New Zealand subsidiaries as collateral for this credit facility. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group at $250.0 million effective November 1, 2005. We requested that the commitment amount with our bank group be reduced to $150.0 million effective May 9, 2003. Under the terms of the credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. The next scheduled borrowing base review is in May 2006.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.0 million in 2005, $1.5 million in 2004, and $1.6 million in 2003. The amount of commitment fees included in interest expense, net was $0.5 million in 2005 and 2004, and $0.6 million in 2003.

Senior Subordinated Notes Due 2009. These notes consisted of $125.0 million of 10-1/4% senior subordinated notes, which were issued at 99.236% of the principal amount on August 4, 1999, and were scheduled to mature on August 1, 2009. These notes were unsecured senior subordinated obligations with interest payable semiannually, on February 1 and August 1. In June 2004, we repurchased $32.1 million of these notes pursuant to a tender offer. In July 2004, we repurchased an additional $0.5 million of these notes, and as of August 1, 2004, we redeemed the remaining $92.5 million in outstanding notes. In 2004, we recorded a charge of $9.5 million related to the repurchase of these notes, which is recorded in Debt retirement costs on the accompanying consolidated statement of income. The costs were comprised of approximately $6.5 million of premiums paid to repurchase the notes, $2.2 million to write-off unamortized debt issuance costs, $0.6 million to write-off unamortized debt discount, and approximately $0.2 million of other costs.

Interest expense on the 10-1/4% senior subordinated notes due 2009, including amortization of debt issuance costs and discount, totaled $7.4 million in 2004 and $13.2 million in 2003.

Senior Notes Due 2011. These notes consist of $150.0 million of 7-5/8% senior notes, which were issued on June 23, 2004 at 100% of the principal amount and will mature on July 15, 2011. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and rank senior to all of our existing and future subordinated indebtedness. Interest on these notes is payable semi-annually on January 15 and July 15, and commenced on January 15, 2005. On or after July 15, 2008, we may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.813% of principal, declining to 100% in 2010 and thereafter. In addition, prior to July 15, 2007, we may redeem up to 35% of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.625% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $3.9 million of debt issuance costs related to these notes, which is included in Debt issuance costs on the accompanying consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. Upon certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these senior notes.

Interest expense on the 7-5/8% senior notes due 2011, including amortization of debt issuance costs totaled $11.9 million in 2005 and $6.2 million in 2004.

Senior Subordinated Notes Due 2012. These notes consist of $200.0 million of 9-3/8% senior subordinated notes, which were issued on April 11, 2002 and will mature on May 1, 2012. The notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank credit facility. Interest on these notes is payable semiannually on May 1 and November 1, with the first interest payment on November 1, 2002. On or after May 1, 2007, we may redeem these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we could have redeemed

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up to 33.33% of these notes with the net proceeds of qualified offerings of our equity at 109.375% of the principal amount of these notes, plus accrued and unpaid interest. Upon certain changes in control of Swift Energy, each holder of these notes will have the right to require us to repurchase the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, a limitation on how much of our own common stock we may repurchase. We are currently in compliance with the provisions of the indenture governing these subordinated notes due 2012.

Interest expense on the 9-3/8% senior subordinated notes due 2012, including amortization of debt issuance costs totaled $19.2 million in both 2005 and 2004 and $19.1 million in 2003.

The maturities on our long-term debt are $0 for 2006, 2007, 2008, 2009, 2010, and $350 million thereafter.

We have capitalized interest on our unproved properties in the amount of $7.2 million, $6.5 million, and $6.8 million, in 2005, 2004, and 2003, respectively.

5. Commitments and Contingencies

Total rental and lease expenses were $3.0 million in 2005, $2.4 million in 2004, and $2.2 million in 2003 and are included in General and administrative, net on our accompanying consolidated statements of income. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $3.4 million for 2006, $3.4 million for 2007, $3.0 million for 2008, $2.7 million for 2009, $2.8 million for 2010, and $13.4 million thereafter or $28.6 million in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas, and in New Zealand.

In the ordinary course of business, we have entered into agreements with drilling and seismic contractors for such services and tubing and pipe inventory commitments. The remaining commitments at December 31, 2005 for these services and materials totaled $28.1 million for 2006 and $1.8 million for 2007.

As of December 31, 2005, we were the managing general partner of two private limited partnerships. Because we serve as the general partner of these entities, under state partnership law we are contingently liable for the liabilities of these partnerships, which liabilities are not material for any of the periods presented in relation to the partnerships respective assets.

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and gas wells. In management s opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on our financial position or results of operations.

6. Stockholders Equity

Stock-Based Compensation Plans. We have three stock option plans that awards are currently granted under, the 2005 Stock Compensation Plan, which was adopted by our Board of Directors in March 2005 and was approved by shareholders at the 2005 annual meeting of shareholders, the 2001 Omnibus Stock Compensation Plan, which was adopted by our Board of Directors in February 2001 and was approved by shareholders at the 2001 annual meeting of shareholders, and the 1990 Non-Qualified Stock Option Plan solely for our independent directors. No further grants will be made under the 2001 Omnibus Stock Compensation Plan or the 1990 Non-Qualified Stock Option Plan, both of which were replaced by the 2005 Stock Compensation Plan, although options remain outstanding under both plans and are accordingly included in the tables below. In addition, we have an employee stock purchase plan and an employee stock ownership plan.

Under the 2005 plan, incentive stock options and other options and awards may be granted to employees, directors, and consultants to purchase shares of common stock. Under the 2001 plan, incentive stock options and other options and awards may be granted to employees to purchase shares of common stock. Under the 1990 non-qualified plan, non-employee members of our Board of Directors were automatically granted options to purchase shares of common stock on a formula basis. All three plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Restricted stock grants become vested in terms ranging from one-third each anniversary date over three years to 50% of the shares 18 months after the grant date and 50% three years after the grant date to one-fifth each anniversary date over five years, stock

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options become exercisable for 20% of the shares on the first anniversary of the grant of the option and are exercisable for an additional 20% per year thereafter. Options granted typically expire ten years after the date of grant or earlier in the event of the optionee s separation from employment. At the time the stock options are exercised, the cash received is credited to common stock and additional paid-in capital. Options issued under these plans also include a reload feature where additional options are granted at the then current market price when mature shares of Swift Energy common stock are used to satisfy the exercise price of an existing stock option grant. When Swift Energy common stock is used to satisfy the exercise price, the net shares actually issued are reflected in the accompanying Statement of Stockholders Equity (see note 1 to table below). We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

The employee stock purchase plan provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. The plan year is from June 1 to the following May 31. The first year of the plan commenced June 1, 1993. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Under this plan for the last three years, we have issued 32,495 shares at a price range of $15.56 to $18.12 in 2005, 50,418 shares at a price range of $9.98 to $10.83 in 2004, and 56,574 shares at a price range of $6.80 to $11.85 in 2003. As of December 31, 2005, 213,140 shares remained available for issuance under this plan.

The following is a summary of our stock options granted under these plans as of December 31, 2005, 2004, and 2003:

	2005		**2004**		**2003**	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,998,668	$ 18.51	3,238,611	$ 16.37	3,018,505	$ 16.64
Options granted	176,262	$ 35.17	415,744	$ 23.36	504,014	$ 13.20
Options canceled	(45,142)	$ 18.94	(64,866)	$ 21.85	(110,901)	$ 21.02
Options exercised[1]	(1,011,609)	$ 9.78	(590,821)	$ 9.83	(173,007)	$ 8.85
Options outstanding, end of period	2,118,179	$ 21.28	2,998,668	$ 18.51	3,238,611	$ 16.37
Options exercisable, end of period	1,085,509	$ 20.98	1,542,571	$ 17.78	1,714,789	$ 15.00
Options available for future grant, end of period	684,368		89,278		494,925	
Estimated weighted average fair value per share of options granted during the year	$ 12.84		$ 9.51		$ 6.93	

The following table summarizes information about stock options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/05	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable At 12/31/05	Wtd. Avg. Exercise Price
$7.00 to $20.99	1,068,842	6.0	$ 12.74	537,474	$ 12.06
$21.00 to $35.99	974,548	5.6	$ 28.89	538,933	$ 29.63
$36.00 to $50.01	74,789	5.1	$ 44.26	9,102	$ 36.33
$7.00 to $50.01	2,118,179	5.8	$ 21.28	1,085,509	$ 20.98

[1] The plans allow for the use of a stock swap in lieu of a cash exercise for options, under certain circumstances. The delivery of Swift Energy common stock, held by the optionee for a minimum of six months, which are considered mature shares, with a fair market value equal to the required purchase price of the shares to which the exercise relates, constitutes a valid stock swap. Options issued under a stock swap also include a reload feature where additional options are granted at the then current market

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price when mature shares of Swift stock are used to satisfy the exercise price of an existing stock option grant. The terms of the plans provide that the mature shares delivered, as full or partial payment in a stock swap , shall again be available for awards under the plans. The options exercised above include 170,762, 81,716 and 30,200 shares in 2005, 2004 and 2003 respectively, related to stock swap shares that were also reloaded.

Restricted Stock. In 2005 and 2004, the Company issued 158,500 and 70,900 shares, respectively, of restricted stock to employees and directors. These shares vest over a three-year to five-year period and remain subject to forfeiture if vesting conditions are not met. In accordance with APB Opinion No. 25, we recognize unearned compensation in connection with the grant of restricted shares equal to the fair value of our common stock on the date of grant. The fair value of these shares when issued in 2005 and 2004 was approximately $38 and $25 per share, and resulted in an increase in Additional paid-in capital and Unearned compensation on the accompanying balance sheet of $6.1 million and $1.8 million, respectively. As restricted shares vest, we reduce unearned compensation and recognize compensation expense. In 2005 and 2004, we recorded expense related to these shares of $1.2 million and less than $0.1 million, respectively, in General and administrative, net on the accompanying statements of income.

The following is a summary of our restricted stock issued to employees and directors under these plans as of December 31, 2005 and 2004:

	2005		2004	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	70,900	$ 25.18		$
Restricted shares granted	158,500	$ 38.31	70,900	$ 25.18
Restricted shares canceled	(7,450)	$ 39.03		$
Restricted shares vested		$		$
Restricted shares outstanding, end of period	221,950	$ 34.09	70,900	$ 25.18

In 2004, we also issued the rights to 30,000 shares of restricted stock to consultants. These shares vest over a two-year period and remain subject to forfeiture if performance conditions are not met within that period. As the performance conditions on 15,000 shares were met in 2005, the vesting conditions were lifted and common stock shares were issued to the non-employees. This issuance is accounted for under FAS No. 123 and as such a measurement date for assessing fair value of the remaining 15,000 shares has not been achieved. We recognized approximately $0.6 million and $0.2 million of compensation cost in 2005 and 2004, and a corresponding increase in Additional paid-in capital, related to these shares. The non-employees perform work that is capitalized to unproved properties, and as such the compensation cost recognized in 2005 and 2004 was recorded to Unproved properties on the accompanying balance sheets.

Employee Stock Ownership Plan. In 1996, we established an Employee Stock Ownership Plan (ESOP) effective January 1, 1996. All employees over the age of 21 with one year of service are participants. This plan has a five-year cliff vesting. The ESOP is designed to enable our employees to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by Swift Energy. Compensation expense is recognized upon vesting when such shares are released to employees. The plan may also acquire Swift Energy common stock, purchased at fair market value. The ESOP can borrow money from Swift Energy to buy Swift Energy common stock. ESOP payouts will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2005, 2004, and 2003, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.2 million for the years ended December 31, 2005, 2004, and 2003, and were made all in common stock, and are recorded as General and administrative, net on the accompanying consolidated statements of income. The shares of common stock contributed to the ESOP plan totaled 4,438, 6,911, and 11,870 shares for the 2005, 2004, and 2003 contributions, respectively.

Employee Savings Plan. We have a savings plan under Section 401(k) of the Internal Revenue Code. Eligible employees may make voluntary contributions into the 401(k) savings plan with Swift contributing on behalf of the eligible employee an amount equal to 100% of the first 2% of compensation and 75% of the next 4% of compensation based on the contributions made by the eligible employees. Our contributions to the 401(k) savings plan were $0.8 million for 2005, $0.7 million for 2004, and $0.6 million for 2003, and are

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recorded as General and administrative, net on the accompanying consolidated statements of income. The contributions in 2005, 2004, and 2003 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 17,920, 24,513, and 34,280 shares for the 2005, 2004, and 2003 contributions, respectively.

Treasury Shares. In March 1997, our Board of Directors approved a common stock repurchase program that terminated as of June 30, 1999. Under this program, we spent approximately $13.3 million to acquire 927,774 shares in the open market at an average cost of $14.34 per share. At December 31, 2005, 449,444 shares remain in treasury (net of 478,330 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $6.4 million and are included in Treasury stock held, at cost on the accompanying balance sheet.

Shareholder Rights Plan. In August 1997, our board of directors declared a dividend of one preferred share purchase right on each outstanding share of Swift Energy common stock. The rights are not currently exercisable but would become exercisable if certain events occurred relating to any person or group acquiring or attempting to acquire 15% or more of our outstanding shares of common stock. Thereafter, upon certain triggers, each right not owned by an acquirer allows its holder to purchase Swift securities with a market value of two times the $150 exercise price.

7. Related-Party Transactions

We are the operator of a number of properties owned by private limited partnerships and, accordingly, charge these entities operating fees. The operating supervision fees charged to the partnerships totaled approximately $0.2 million in 2005, 2004 and 2003, and are recorded as reductions of General and administrative, net. We also have been reimbursed for administrative, and overhead costs incurred in conducting the business of the private limited partnerships, which totaled less than $0.1 million, $0.2 million, and $0.4 million in 2005, 2004, and 2003, respectively, and are recorded as reductions in General and administrative, net. Included in Accounts receivable and Accounts payable and accrued liabilities on the accompanying balance sheets, is approximately $0.4 million and $0.5 million, respectively, in receivables from and payables to the partnerships at December 31, 2005.

We receive research, technical writing, publishing, and website-related services from Tec-Com Inc., a corporation located in Knoxville, Tennessee and controlled and majority owned by the sister of the Company s Chairman of the Board and aunt of the Company s Chief Executive Officer. In 2005, 2004 and 2003, we paid approximately $0.4 million per year to Tec-Com for such services pursuant to the terms of the contract between the parties. The contract was renewed June 30, 2004 on substantially the same terms and expires June 30, 2007. We believe that the terms of this contract are consistent with third party arrangements that provide similar services.

As a matter of corporate governance policy and practice, related party transactions are annually presented and considered by the Corporate Governance Committee of our Board of Directors in accordance with the Committee s charter.

8. Foreign Activities

As of December 31, 2005, our gross capitalized oil and gas property costs in New Zealand totaled approximately $292.2 million. Approximately $262.8 million has been included in the Proved properties portion of our oil and gas properties, while $29.4 million is included as Unproved properties. Our functional currency in New Zealand is the U.S. Dollar. Net assets of our New Zealand operations total $241.9 million at December 31, 2005. Our capital expenditures on oil and gas property in New Zealand were approximately $50.8 million in 2005.

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9. Acquisitions and Dispositions

In November 2005, we acquired interests in the South Bearhead Creek field in Central Louisiana. This field is approximately 50 miles south of our Masters Creek field. We paid approximately $24.3 million in cash for these interests. After taking into account internal acquisition costs of $2.6 million, and assumed liabilities of $1.4 million, our total cost was $28.3 million. We allocated $26.2 million of the acquisition price to Proved Properties, $2.5 million to Unproved Properties, and recorded a liability for $0.4 million to Asset retirement obligation on our accompanying consolidated balance sheet. In December 2005 we acquired additional interests in this field. We paid approximately $4.6 million in cash for these additional interests. After taking into account internal acquisition costs of $0.6 million, our total cost was $5.2 million. We allocated $4.9 million of the acquisition price to Proved Properties, $0.4 million to Unproved Properties, and recorded a liability for $0.1 million to Asset retirement obligation on our accompanying consolidated balance sheet. These acquisitions were accounted for by the purchase method of accounting. We made these acquisitions to increase our exploration and development opportunities in this area. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward, however, given the acquisitions were in November and December 2005, these amounts were immaterial.

In December 2004, we acquired interests in two fields in South Louisiana, the Bay de Chene and Cote Blanche Island fields. We paid approximately $27.7 million in cash for these interests. After taking into account internal acquisition costs of $2.8 million, our total cost was $30.5 million. We allocated $27.8 million of the acquisition price to Proved properties, $5.1 million to Unproved properties, we also recorded $0.5 million to Restricted assets, and recorded a liability of $2.9 million to Asset retirement obligation on our accompanying consolidated balance sheet. This acquisition was accounted for by the purchase method of accounting. We made this acquisition to increase our exploration and development opportunities in South Louisiana. The revenues and expenses from these properties have been included in our accompanying consolidated statements of income from the date of acquisition forward, however, given the acquisition was in late December 2004, these amounts were immaterial for that year.

10. Condensed Consolidating Financial Information

In December 2005, we amended the indenture for our 9-3/8% Senior Subordinated Notes due 2012 and our 7-5/8% Senior Notes due 2011 to reflect our new holding company organizational structure (as discussed in Note 1). As part of this restructuring our indentures were amended so that both Swift Energy Company and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) became co-obligors of these senior notes and senior subordinated debt. The co-obligations are full and unconditional and are joint and several. Prior to this restructure, Swift Energy Company was the sole obligor. The following is condensed consolidating financial information for Swift Energy Company, Swift Energy Operating, LLC, and significant subsidiaries:

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Condensed Consolidating Balance Sheets

	December 31, 2005				
(in 000 s)	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$	$ 92,788	$ 22,267	$	$ 115,055
Property and equipment		862,717	216,316		1,079,034
Investment in subsidiaries (equity method)	607,318		410,612	(1,017,930)	
Other assets		31,955	682	(22,313)	10,324
Total assets	$ 607,318	$ 987,460	$ 649,877	$ (1,040,243)	$ 1,204,413
LIABILITIES AND STOCKHOLDERS EQUITY					
Current liabilities	$	$ 85,472	$ 12,949	$	$ 98,421
Long-term liabilities		491,376	29,610	(22,313)	498,674
Stockholders Equity	607,318	410,612	607,318	(1,017,930)	607,318
Total liabilities and stockholders equity	$ 607,318	$ 987,460	$ 649,877	$ (1,040,243)	$ 1,204,413

	December 31, 2004			
(in 000 s)	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS				
Current assets	$ 38,713	$ 15,673	$	$ 54,386
Property and equipment	719,209	204,229		923,438
Investment in subsidiaries (equity method)	104,003		(104,003)	
Other assets	116,537	2,364	(106,152)	12,749
Total assets	$ 978,462	$ 222,265	$ (210,155)	$ 990,573
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities	$ 60,160	$ 8,458	$	$ 68,618
Long-term liabilities	444,130	109,805	(106,152)	447,783

Stockholders Equity		474,172		104,003		(104,003)		474,172
Total liabilities and stockholders equity	$	978,462	$	222,265	$	(210,155)	$	990,573

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	December 31, 2003			
(in 000 s)	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS				
Current assets	$ 25,324	$ 8,137	$	$ 33,461
Property and equipment	629,310	186,497		815,807
Investment in subsidiaries (equity method)	87,780		(87,780)	
Other assets	109,088	2,534	(101,051)	10,571
Total assets	$ 851,502	$ 197,168	$ (188,831)	$ 859,839
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities	$ 63,227	$ 6,126	$	$ 69,353
Long-term liabilities	390,884	103,262	(101,051)	393,095
Stockholders Equity	397,391	87,780	(87,780)	397,391
Total liabilities and stockholders equity	$ 851,502	$ 197,168	$ (188,831)	$ 859,839

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Condensed Consolidating Statements of Income

	December 31, 2005				
(in 000 s)	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$	$ 354,367	$ 68,893	$ (34)	$ 423,226
Expenses		198,237	46,583	(34)	244,787
Income (loss) before the following:		156,130	22,309		178,440
Equity in net earnings of subsidiaries	115,778		97,880	(213,659)	
Income before income taxes	115,778	156,130	120,190	(213,659)	178,440
Income tax provision (benefit)		58,249	4,412		62,661
Net income	$ 115,778	$ 97,881	$ 115,778	$ (213,659)	$ 115,778

	Year Ended December 31, 2004			
(in 000 s)	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ 256,608	$ 53,817	$ (147)	$ 310,277
Expenses	171,147	37,838	(147)	208,837
Income (loss) before the following:	85,461	15,979		101,440
Equity in net earnings of subsidiaries	14,733		(14,733)	
Income before income taxes	100,194	15,979	(14,733)	101,440
Income tax provision (benefit)	31,743	1,247		32,989
Net income	$ 68,451	$ 14,733	$ (14,733)	$ 68,451

	Year Ended December 31, 2003			
(in 000 s)	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ 163,237	$ 48,594	$ (2,929)	$ 208,901
Expenses	123,327	37,764	(2,929)	158,162
Income (loss) before the following:	39,909	10,830		50,739
Equity in net earnings of subsidiaries	9,421		(9,421)	
Income before income taxes	49,330	10,830	(9,421)	50,739
Income tax provision (benefit)	15,292	1,177		16,469
Income before change in accounting principle	34,038	9,653	(9,421)	34,271
Cumulative effect of change in accounting principle (net of taxes)	(4,144)	(232)		(4,377)
Net income	$ 29,894	$ 9,421	$ (9,421)	$ 29,894

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Condensed Consolidating Statements of Cash Flow

(in 000 s)	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consol.
	December 31, 2005				
Cash flow from operations	$	$ 236,790	$ 48,543	$	$ 285,333
Cash flow from investing activities		(194,909)	(48,837)	(3,672)	(240,074)
Cash flow from financing activities		2,825	3,672	(3,672)	2,825
Net increase in cash	$	$ 44,706	$ 3,379	$	$ 48,084
Cash, beginning of period		205	4,715		4,920
Cash, end of period	$	$ 44,911	$ 8,094	$	$ 53,005

(in 000 s)	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
	Year Ended December 31, 2004			
Cash flow from operations	$ 147,114	$ 35,469	$	$ 182,583
Cash flow from investing activities	(158,308)	(35,878)	5,100	(189,086)
Cash flow from financing activities	10,357	5,100	(5,100)	10,357
Net increase (decrease) in cash	(837)	4,691		3,854
Cash, beginning of period	1,042	24		1,066
Cash, end of period	$ 205	$ 4,715	$	$ 4,920

(in 000 s)	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
	Year Ended December 31, 2003			
Cash flow from operations	$ 81,376	$ 29,451	$	$ 110,827

Cash flow from investing activities	(101,756)	(32,454)	3,157	(131,053)
Cash flow from financing activities	17,476	3,157	(3,157)	17,476
Net increase (decrease) in cash	(2,904)	154		(2,750)
Cash, beginning of period	3,947	(131)		3,816
Cash, end of period	$ 1,043	$ 23	$	$ 1,066

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11. Segment Information

The Company has two reportable segments, one domestic and one foreign, which are in the business of crude oil and natural gas exploration and production. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate our performance based on profit or loss from oil and gas operations before price-risk management and other, net, general and administrative, net, interest expense, net and debt retirement costs. Our reportable segments are managed separately based on their geographic locations. Financial information by operating segment is presented below:

	2005		
	Domestic	New Zealand	Total
Oil and gas sales	$ 355,872,616	$ 67,893,629	$ 423,766,245
Costs and Expenses:			
Depreciation, depletion, and amortization	(81,123,588)	(26,354,199)	(107,477,787)
Accretion of asset retirement obligation	(626,134)	(134,908)	(761,042)
Lease operating cost	(34,941,430)	(12,380,411)	(47,321,841)
Severance and other taxes	(37,805,742)	(4,370,763)	(42,176,505)
Income from oil and gas operations	$ 201,375,722	$ 24,653,348	$ 226,029,070
Price-risk management and other, net			(539,756)
General and administrative, net			(22,176,362)
Interest expense, net			(24,873,401)
Income before Income Taxes and Change in Accounting Principle			$ 178,439,551
Property and Equipment, net	$ 863,154,295	$ 215,879,444	$ 1,079,033,739
Total Assets	962,469,183	241,943,439	1,204,412,622
Capital Expenditures	$ 215,785,080	$ 48,689,826	$ 264,474,906

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	Domestic	2004 New Zealand	Total
Oil and gas sales	$ 258,663,936	$ 52,621,236	$ 311,285,172
Costs and Expenses:			
Depreciation, depletion, and amortization	(62,283,350)	(19,297,478)	(81,580,828)
Accretion of asset retirement obligation	(505,174)	(168,480)	(673,654)
Lease operating cost	(30,191,889)	(11,022,367)	(41,214,256)
Severance and other taxes	(26,713,592)	(3,687,701)	(30,401,293)
Income from oil and gas operations	$ 138,969,931	$ 18,445,210	$ 157,415,141
Price-risk management and other, net			(1,008,398)
General and administrative, net			(17,787,125)
Interest expense, net			(27,643,108)
Debt retirement costs			(9,536,268)
Income before Income Taxes and Change in Accounting Principle			$ 101,440,242
Property and Equipment, net	$ 731,890,068	$ 191,548,092	$ 923,438,160
Total Assets	778,611,100	211,962,047	990,573,147
Capital Expenditures	$ 162,535,617	$ 35,755,820	$ 198,291,437

	Domestic	2003 New Zealand	Total
Oil and gas sales	$ 164,167,390	$ 46,865,249	$ 211,032,639
Costs and Expenses:			
Depreciation, depletion, and amortization	(44,645,939)	(18,426,118)	(63,072,057)
Accretion of asset retirement obligation	(623,948)	(233,408)	(857,356)
Lease operating cost	(24,022,412)	(9,810,786)	(33,833,198)
Severance and other taxes	(15,290,669)	(3,742,935)	(19,033,604)
Income from oil and gas operations	$ 79,584,422	$ 14,652,002	$ 94,236,424
Price-risk management and other, net			(2,131,656)
General and administrative, net			(14,097,066)
Interest expense, net			(27,268,524)

Income before Income Taxes and Change in Accounting Principle			$ 50,739,178
Property and Equipment, net	$ 641,366,888	$ 174,440,115	$ 815,807,003
Total Assets	672,721,551	187,116,993	859,838,544
Capital Expenditures	$ 114,443,475	$ 30,059,705	$ 144,503,180

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Supplementary Information
Swift Energy Company and Subsidiaries
Oil and Gas Operations (Unaudited)

Capitalized Costs. The following table presents our aggregate capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, and amortization:

	Total	Domestic	New Zealand
December 31, 2005:			
Proved oil and gas properties	$ 1,731,866,298	$ 1,468,981,981	$ 262,884,317
Unproved oil and gas properties	87,553,220	58,196,531	29,356,689
	1,819,419,518	1,527,178,512	292,241,006
Accumulated depreciation, depletion, and amortization	(748,327,443)	(671,117,089)	(77,210,354)
Net capitalized costs	$ 1,071,092,075	$ 856,061,423	$ 215,030,652
December 31, 2004:			
Proved oil and gas properties	$ 1,479,681,903	$ 1,271,354,490	$ 208,327,413
Unproved oil and gas properties	80,121,509	46,751,416	33,370,093
	1,559,803,412	1,318,105,906	241,697,506
Accumulated depreciation, depletion, and amortization	(641,917,990)	(590,906,014)	(51,011,976)
Net capitalized costs	$ 917,885,422	$ 727,199,892	$ 190,685,530

Of the $58.2 million of domestic Unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2005, excluded from the amortizable base, $28.7 million was incurred in 2005, $23.9 million was incurred in 2004, $2.2 million was incurred in 2003, and $3.4 million was incurred in prior years. When we are in an active drilling mode, we evaluate the majority of these unproved costs within a two to four year time frame.

Of the $29.4 million of New Zealand Unproved property costs at December 31, 2005, excluded from the amortizable base, $7.3 million was incurred in 2005, $5.9 million was incurred in 2004, $3.2 million was incurred in 2003, and $13.0 million was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there within a two to four year time frame.

Capitalized asset retirement obligations have been included in the Proved properties as of December 31, 2005, 2004, and 2003 as we adopted SFAS No. 143 Accounting for Asset Retirement Obligations effective January 1, 2003.

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Costs Incurred. The following table sets forth costs incurred related to our oil and gas operations:

	Year Ended December 31, 2005		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 31,429,343	$ 31,429,343	$
Lease acquisitions and prospect costs[1]	41,397,277	34,502,163	6,895,114
Exploration	52,350,339	38,424,995	13,925,344
Development	140,137,380	110,975,385	29,161,995
Total acquisition, exploration, and development[2]	$ 265,314,339	$ 215,331,886	$ 49,982,453
Processing plants	$ 928,919	$ 67,628	$ 861,291
Field compression facilities	14,932	14,932	
Total plants and facilities	$ 943,851	$ 82,560	$ 861,291
Total costs incurred[3]	$ 266,258,190	$ 215,414,446	$ 50,843,744

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 31,771,094	$ 31,771,094	$
Lease acquisitions and prospect costs[1]	34,545,393	27,713,059	6,832,334
Exploration	17,430,265	16,714,982	715,283
Development	105,947,485	78,163,289	27,784,196
Total acquisition, exploration, and development [2]	$ 189,694,237	$ 154,362,424	$ 35,331,813
Processing plants	$ 1,283,515	$ 147,317	$ 1,136,198
Field compression facilities	1,028,091	1,028,091	
Total plants and facilities	$ 2,311,606	$ 1,175,408	$ 1,136,198
Total costs incurred[3]	$ 192,005,843	$ 155,537,832	$ 36,468,011

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 1,942,868	$ 1,635,316	$ 307,552
Lease acquisitions and prospect costs[1]	18,869,099	12,440,144	6,428,955
Exploration	14,467,455	11,789,700	2,677,755
Development	116,451,112	100,549,351	15,901,761
Total acquisition, exploration, and development [2]	$ 151,730,534	$ 126,414,511	$ 25,316,023

Processing plants	$ 6,192,199	$ 907,771	$ 5,284,428
Field compression facilities	3,521,522	3,521,522	
Total plants and facilities	$ 9,713,721	$ 4,429,293	$ 5,284,428
Total costs incurred[3]	$ 161,444,255	$ 130,843,804	$ 30,600,451

1 These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties in 2005, 2004, and 2003 were $30.4 million, $17.8 million, and $20.7 million, respectively.

2 Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $18.8 million, $13.1 million, and $11.5 million in 2005, 2004, and 2003, respectively. In addition, total includes $7.2 million, $6.5 million , and $6.8 million in 2005, 2004, and 2003, respectively, of capitalized interest on unproved properties.

3 Asset retirement obligations incurred have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2005, 2004, and 2003, as we adopted SFAS No. 143 Accounting for Asset Retirement Obligations effective January 1, 2003.

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Results of Operations.

	Year Ended December 31, 2005		
	Total	Domestic	New Zealand
Oil and gas sales	$ 423,766,245	$ 355,872,616	$ 67,893,629
Lease operating cost	(47,321,841)	(34,941,430)	(12,380,411)
Severance and other taxes	(42,176,505)	(37,805,742)	(4,370,763)
Depreciation, depletion, and amortization	(106,037,775)	(79,926,245)	(26,111,530)
Accretion of asset retirement obligation	(761,042)	(626,134)	(134,908)
	227,469,082	202,573,065	24,896,017
Provision for income taxes	79,878,043	74,953,611	4,924,432
Results of producing activities	$ 147,591,039	$ 127,619,454	$ 19,971,585
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.78	$ 1.86	$ 1.58

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Oil and gas sales	$ 311,285,172	$ 258,663,936	$ 52,621,236
Lease operating cost	(41,214,256)	(30,191,889)	(11,022,367)
Severance and other taxes	(30,401,293)	(26,713,592)	(3,687,701)
Depreciation, depletion and amortization	(80,504,043)	(61,478,364)	(19,025,679)
Accretion of asset retirement obligation	(673,654)	(505,174)	(168,480)
	158,491,926	139,774,917	18,717,009
Provision for income taxes	53,093,022	51,576,944	1,516,078
Results of producing activities	$ 105,398,904	$ 88,197,973	$ 17,200,931
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.38	$ 1.46	$ 1.17

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Oil and gas sales	$ 211,032,639	$ 164,167,390	$ 46,865,249
Lease operating cost	(33,833,198)	(24,022,412)	(9,810,786)
Severance and other taxes	(19,033,604)	(15,290,669)	(3,742,935)
Depreciation, depletion and amortization	(62,037,680)	(43,818,709)	(18,218,971)
Accretion of asset retirement obligation	(857,356)	(623,948)	(233,408)
	95,270,801	80,411,652	14,859,149
Provision for income taxes	32,321,635	29,696,023	2,625,612
Results of producing activities	$ 62,949,166	$ 50,715,629	$ 12,233,537

Amortization per physical unit of production (equivalent Mcf of gas)	$	1.17	$	1.30	$	0.94

These results of operations do not include the losses from our hedging activities of $1.1 million, $1.3 million, and $2.8 million for 2005, 2004 and 2003, respectively. Our lease operating costs per Mcfe produced were $0.79 in 2005, $0.71 in 2004, and $0.64 in 2003.

The accretion of asset retirement obligation has been included in the 2005, 2004, and 2003 periods, as we adopted SFAS No. 143 Accounting for Asset Retirement Obligations effective January 1, 2003.

We used our effective tax rate in each country to compute the provision for income taxes in each year presented.

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Supplementary Reserves Information. The following information presents estimates of our proved oil and gas reserves. Reserves were determined by us and audited by H. J. Gruy and Associates, Inc. (Gruy), independent petroleum consultants. Gruy has audited 100% of our proved reserves. Gruy s audit was conducted according to standards approved by the Board of Directors of the Society of Petroleum Engineers, Inc. and included examination, on a test basis, of the evidence supporting our reserves. Gruy s audit was based upon review of production histories and other geological, economic, and engineering data provided by Swift. Where Gruy had material disagreements with Swift reserves estimates, we revised our estimates to be in agreement. Gruy s report dated January 25, 2006, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2005, and includes definitions and assumptions that served as the basis for the audit of proved reserves and future net cash flows. Such definitions and assumptions should be referred to in connection with the following information:

Estimates of Proved Reserves

	Total		Domestic		New Zealand	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)
Proved reserves as of December 31, 2002	326,731,672	70,438,963	239,824,062	59,029,640	86,907,610	11,409,323
Revisions of previous estimates[1]	(6,445,114)	4,975,920	(1,418,312)	3,497,022	(5,026,802)	1,478,898
Purchases of minerals in place	273,623	35,472	273,623	35,472		
Sales of minerals in place	(3,984,209)	(228,505)	(3,984,209)	(228,505)		
Extensions, discoveries, and other additions	47,231,609	9,730,665	21,370,151	8,018,766	25,861,458	1,711,899
Production	(28,002,719)	(4,192,612)	(13,744,040)	(3,336,702)	(14,258,679)	(855,910)
Proved reserves as of December 31, 2003	335,804,862	80,759,903	242,321,275	67,015,693	93,483,587	13,744,210
Revisions of previous estimates[1]	(3,306,705)	(1,117,715)	(1,619,531)	695,274	(1,687,174)	(1,812,989)
Purchases of minerals in place	9,808,953	5,602,508	9,808,953	5,602,508		
Sales of minerals in place	(2,524,760)	(44,803)	(2,524,760)	(44,803)		
Extensions, discoveries, and other additions	2,205,670	830,111	2,205,670	830,111		
Production	(23,741,726)	(5,762,796)	(12,299,772)	(4,959,740)	(11,441,954)	(803,056)
Proved reserves as of December 31,	318,246,294	80,267,208	237,891,835	69,139,043	80,354,459	11,128,165

2004						
Revisions of previous estimates[1]	(21,461,605)	(2,199,673)	(13,751,124)	(1,023,808)	(7,710,481)	(1,175,866)
Purchases of minerals in place	9,336,088	3,262,761	9,336,088	3,262,761		
Sales of minerals in place	(3,737,714)	(100,121)	(3,737,714)	(100,121)		
Extensions, discoveries, and other additions	8,699,329	3,819,595	7,275,207	3,722,744	1,424,122	96,851
Production	(23,609,242)	(5,996,714)	(11,739,485)	(5,217,343)	(11,869,757)	(779,371)
Proved reserves as of December 31, 2005	287,473,150	79,053,056	225,274,807	69,783,276	62,198,343	9,269,779
Proved developed reserves: [2]						
December 31, 2002	233,514,572	35,928,395	149,731,562	26,530,112	83,783,010	9,398,283
December 31, 2003	210,119,927	45,525,366	138,173,341	38,767,983	71,946,586	6,757,383
December 31, 2004	193,310,761	42,037,852	140,549,052	36,628,873	52,761,709	5,408,979
December 31, 2005	152,001,133	37,989,821	125,367,690	35,298,324	26,633,443	2,691,497

1 Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil, NGL, and natural gas prices at each year-end. Proved reserves, as of December 31, 2005, were based upon prices in effect at year-end. Our hedges at year-end 2005 consisted of natural gas price floors with strike prices mostly lower than the period end price and thus would not materially affect prices used in these calculations. The weighted average of 2005 year-end prices for total, domestic, and New Zealand were $8.94, $10.36, and $3.79 per Mcf of natural gas, $60.12, $60.00, and $60.98 per barrel of oil, and $31.40, $33.28 and $19.20 per barrel of NGL, respectively. This compares to $5.16, $5.87, and $3.07 per Mcf of natural gas, $41.07, $42.21, and $33.60 per barrel of oil, and $25.48, $26.49 and $20.48 per barrel of NGL as of December 31, 2004, for total, domestic, and New Zealand, respectively. The weighted average of 2003 year-end prices for total, domestic, and New Zealand were $4.56, $5.53, and $2.04 per Mcf of natural gas, $30.16, $30.88, and $26.78 per barrel of oil, and $20.61, $21.81, and $14.10 per barrel of NGL, respectively.

2 At December 31, 2005, 50% of our reserves were proved developed, compared to 56% at December 31, 2004, 59% at December 31, 2003, and 60% at December 31, 2002.

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Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows:

	Year Ended December 31, 2005		
	Total	Domestic	New Zealand
Future gross revenues	$ 6,917,103,123	$ 6,194,560,214	$ 722,542,909
Future production costs	(1,334,822,738)	(1,122,637,935)	(212,184,803)
Future development costs	(710,343,331)	(667,526,650)	(42,816,681)
Future net cash flows before income taxes	4,871,937,054	4,404,395,629	467,541,425
Future income taxes	(1,538,799,956)	(1,461,577,946)	(77,222,010)
Future net cash flows after income taxes	3,333,137,098	2,942,817,683	390,319,415
Discount at 10% per annum	(1,173,767,635)	(1,048,193,951)	(125,573,684)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,159,369,463	$ 1,894,623,732	$ 264,745,731

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Future gross revenues	$ 4,711,060,300	$ 4,122,705,861	$ 588,354,439
Future production costs	(1,029,449,670)	(819,035,166)	(210,414,504)
Future development costs	(480,093,684)	(434,305,537)	(45,788,147)
Future net cash flows before income taxes	3,201,516,946	2,869,365,158	332,151,788
Future income taxes	(896,135,438)	(866,598,544)	(29,536,894)
Future net cash flows after income taxes	2,305,381,508	2,002,766,614	302,614,894
Discount at 10% per annum	(840,436,013)	(746,227,690)	(94,208,323)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,464,945,495	$ 1,256,538,924	$ 208,406,571

	Year Ended December 31, 2003		
	Total	Domestic	New Zealand
Future gross revenues	$ 3,805,349,886	$ 3,279,884,680	$ 525,465,206
Future production costs	(831,430,479)	(678,983,441)	(152,447,038)
Future development costs	(331,816,723)	(301,874,087)	(29,942,636)
Future net cash flows before income taxes	2,642,102,684	2,299,027,152	343,075,532
Future income taxes	(729,624,048)	(657,354,849)	(72,269,199)
Future net cash flows after income taxes	1,912,478,636	1,641,672,303	270,806,333
Discount at 10% per annum	(777,622,101)	(678,769,827)	(98,852,274)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,134,856,535	$ 962,902,476	$ 171,954,059

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

2. The estimated future gross revenues of proved reserves are priced on the basis of year-end prices, except in those instances where fixed and determinable gas price escalations are covered by contracts limited to the price we reasonably expect to receive.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as asset retirement obligation costs, net of salvage value, based on year-end cost estimates and the estimated effect of future income taxes.

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4. Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future oil and gas producing activities, and tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on year-end oil and gas prices for each period. Our hedges at year-end 2005 consisted mainly of natural gas price floors with strike prices lower than the period end price and thus did not materially affect prices used in these calculations. Subsequent changes to such year-end oil and gas prices could have a significant impact on discounted future net cash flows. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations using hedge adjusted prices in effect as of the period end date presented (see Note 1 to the consolidated financial statements). Application of these rules during periods of relatively low oil and gas prices, even if of short-term seasonal duration, may result in non-cash write-downs.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of our oil and gas property reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment, and the risks inherent in reserves estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Year Ended December 31,		
	2005	**2004**	**2003**
Beginning balance	$ 1,464,945,495	$ 1,134,856,535	$ 836,869,791
Revisions to reserves proved in prior years			
Net changes in prices, and production costs	1,232,876,998	398,333,372	218,104,882
Net changes in future development costs	(173,219,347)	(117,672,270)	(108,603,152)
Net changes due to revisions in quantity estimates	(138,969,442)	(12,754,357)	48,194,999
Accretion of discount	199,799,374	152,715,946	116,136,717
Other	17,191,849	49,111,385	(57,822,716)
Total revisions	1,137,679,432	469,734,076	216,010,730
New field discoveries and extensions, net of future production and development costs	152,461,162	30,609,517	243,183,114
Purchases of minerals in place	99,129,117	118,575,886	1,019,290
Sales of minerals in place	(10,164,069)	(7,339,601)	(13,660,012)
Sales of oil and gas produced, net of production costs	(334,267,899)	(239,669,623)	(158,165,836)
Previously estimated development costs incurred	100,614,837	98,924,021	77,404,994
Net change in income taxes	(451,028,612)	(140,745,316)	(67,805,536)
Net change in standardized measure of discounted future net cash flows	694,423,968	330,088,960	297,986,744
Ending balance	$ 2,159,369,463	$ 1,464,945,495	$ 1,134,856,535

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Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2004 and 2005:

	Revenues	Income Before Income Taxes, and Change in Accounting Principle	Income Before Change in Accounting Principle	Net Income	Basic EPS Income Before Change In Accounting Principle	Diluted EPS Income Before Change In Accounting Principle	Basic EPS Net Income	Diluted EPS Net Income
2004:								
First	$ 65,355,730	$ 20,086,182	$ 14,587,854	$ 14,587,854	$ 0.53	$ 0.52	$ 0.53	$ 0.52
Second	71,043,735	20,001,147	12,897,927	12,897,927	0.46	0.46	0.46	0.46
Third	74,942,751	19,472,596	14,130,717	14,130,717	0.51	0.50	0.51	0.50
Fourth	98,934,558	41,880,317	26,834,419	26,834,419	0.96	0.93	0.96	0.93
Total	$ 310,276,774	$ 101,440,242	$ 68,450,917	$ 68,450,917	$ 2.46	$ 2.41	$ 2.46	$ 2.41
2005:								
First	$ 95,620,684	$ 39,758,619	$ 25,689,152	$ 25,689,152	$ 0.91	$ 0.89	$ 0.91	$ 0.89
Second	104,299,925	41,778,041	27,881,658	27,881,658	0.98	0.96	0.98	0.96
Third	100,853,505	42,901,655	27,506,899	27,506,899	0.96	0.92	0.96	0.92
Fourth	122,452,375	54,001,236	34,700,747	34,700,747	1.20	1.16	1.20	1.16
Total	$ 423,226,489	$ 178,439,551	$ 115,778,456	$ 115,778,456	$ 4.06	$ 3.95	$ 4.06	$ 3.95

There were no extraordinary items in 2004 or 2005. As described in Note 4 to the consolidated financial statements, in 2004 we incurred debt retirement costs relating to the repurchase of our 10-1/4% senior subordinated notes due 2009 totaling $9.5 million. Debt retirement costs totaled $2.7 million, $6.8 million and less than $0.1 million in the second, third and fourth quarters of 2004, respectively.

The sum of the individual quarterly net income per common share amounts may not agree with year-to-date net income per common share as each quarterly computation is based on the weighted average number of common shares outstanding during that period. In addition, certain potentially dilutive securities were not included in certain of the quarterly computations of diluted net income per common share because to do so would have been antidilutive.

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Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We have had no changes in or disagreements with our independent accountants since our Board of Directors June 12, 2002 appointment, based upon the recommendation of our Audit Committee, of Ernst & Young LLP as Swift s independent auditors for the fiscal year ended December 31, 2002, replacing Arthur Andersen LLP as our independent auditors. That change was reported by Swift in a Current Report on Form 8-K dated June 12, 2002, filed with the SEC on June 18, 2002.

Item 9A. Controls and Procedures

The Company s chief executive officer and chief financial officer have evaluated the Company s disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the Exchange Act) as of the end of the period covered by the report. Based on that evaluation, they have concluded that such disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company required under the Exchange Act to be disclosed in this report. There were no significant changes in the Company s internal controls that could significantly affect such controls subsequent to the date of their evaluation.

Management s Report On Internal Control Over Financial Reporting as of December 31, 2005 is included in Item 8. Financial Statements and Supplementary Data. The Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting is also included in Item 8.

Item 9B. Other Information

None

PART III

Item 10. Directors and Executive Officers of the Registrant

The information required under Item 10 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 9, 2006, annual shareholders meeting is incorporated herein by reference.

Item 11. Executive Compensation

The information required under Item 11 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 9, 2006, annual shareholders meeting is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required under Item 12 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 9, 2006, annual shareholders meeting is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

The information required under Item 13 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 9, 2006, annual shareholders meeting is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required under Item 14 which will be set forth in our definitive proxy statement to be filed within 120 days after the close of the fiscal year end in connection with our May 9, 2006, annual shareholders meeting is incorporated by reference.

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PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) 1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 27, 2006, and the data contained therein are included in Item 8 hereof:

2. Financial Statement Schedules

[None]

3. Exhibits

2	Plan and Agreement and Articles of Merger to Form Holding Company, dated as of December 21, 2005, but effective at 9:00 a.m., local time in Austin, Texas on December 28, 2005, by and among Swift Energy Company, New Swift Energy Company and Swift Energy Operating, LLC (incorporated by reference as Exhibit 2.1 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
3.1	Restated Articles of Incorporation of Swift Energy Company (incorporated by reference as Exhibit 3.3 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
3.2	Amended and Restated Bylaws of Swift Energy Company, as amended through December 28, 2005 (incorporated by reference as Exhibit 3.5 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
3.3.	Certificate of Designation of Series A Junior Participating Preferred Stock of Swift Energy Company (incorporated by reference as Exhibit 3.4 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
4.1	Indenture dated as of April 16, 2002 between Swift Energy Company and Bank One, N.A., as Trustee (incorporated by reference as Exhibit 4.1 to Swift Energy Company s Form 8-K filed April 16, 2002, File No. 1-08754)
4.2	First Supplemental Indenture dated as of April 16, 2002 between Swift Energy Company and Bank One, N.A., including the form of 9 3/8% Senior Subordinated Notes due 2012 (incorporated by reference as Exhibit 4.2 to Swift Energy Company s Form 8-K filed April 16, 2002, File No. 1-08754).

4.3	Second Supplemental Indenture dated as of December 28, 2005 between Swift Energy Company and J.P. Morgan Trust Company, National Association as succesor Trustee to Bank One, NA (incorporated by reference as Exhibit 4.1 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
4.4	Indenture dated as of June 23, 2004 between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference as Exhibit 4.1 to Swift Energy Company s Form 8-K filed June 25, 2004, File No. 1-08754).
4.5	First Supplemental Indenture dated as of June 23, 2004 between Swift Energy Company and Wells Fargo Bank, National Association, as Trustee, including the form of 7 5/8% Senior Notes (incorporated by reference as Exhibit 4.2 to Swift Energy Company s Form 8-K filed June 25, 2004, File No. 1-08754).
4.6	Second Supplemental Indenture dated as of December 28, 2005 between Swift Energy Company and Wells Fargo Bank. National Association, as Trustee (incorporated by reference as Exhibit 4.2 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
4.7	Amended and Restated Rights Agreement between Swift Energy Company and American Stock Transfer & Trust Company, dated March 31, 1999 (incorporated by reference to Swift Energy Company s Amendment No. 1 to Form 8-A filed April 7, 1999, File No. 1-08754).
4.8	Amendment No. 1 to the Rights Agreement dated December 12, 2005 between Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent (incorporated by reference as Exhibit 4.3 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
4.9	Assignment, Assumption, Amendment and Novation Agreement between Swift Energy Company, New Swift Energy Company and American Stock Transfer & Trust Company, as Rights Agent effective at 9:00 a.m., local time in Austin, Texas on December 28, 2005 (incorporated by reference as Exhibit 4.4 to Swift Energy Company s Form 8-K filed December 29, 2005, File No. 1-08754).
10.1	Indemnity Agreement dated July 8, 1988 between Swift Energy Company and A. Earl Swift (plus schedule of other persons with whom Indemnity Agreements have been entered into) (incorporated by reference as Exhibit 10.1 to Swift Energy Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2001, File No. 1-08754).
10.2 +	Amended and Restated Swift Energy Company 1990 Nonqualified Stock Option Plan, as of May 13, 1997 (incorporated by reference from Swift Energy Company s definitive proxy statement for the annual shareholders meeting filed April 14, 1997, File No. 1-08754).
10.3 +	Amended and Restated Swift Energy Company 1990 Stock Compensation Plan, as of May 13, 1997 (incorporated by reference from Swift Energy Company s definitive proxy statement for the annual shareholders meeting filed April 14, 1997, File No. 1-08754).
10.4 +	Amendment to the Swift Energy Company 1990 Stock Compensation Plan, as of May 9, 2000 (incorporated by reference as Exhibit 4.2 to the Swift Energy Company registration statement No. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).

10.5 +	Swift Energy Company 2001 Omnibus Stock Compensation Plan , as of January 1, 2001 (incorporated by reference as Exhibit 4.3 to the Swift Energy Company registration statement no. 333-67242 on Form S-8 filed August 10, 2001, File No. 1-08754).
10.6 +	Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Form 8-K filed May 12, 2005, File No. 1-08754).
10.7 +	Amended and Restated Employment Agreement dated as of November 15, 2000 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and A. Earl Swift (incorporated by reference as Exhibit 10.12 to Swift Energy Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).
10.8 +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Terry E. Swift (incorporated by reference as Exhibit 10.2 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.9 +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and James M. Kitterman (incorporated by reference as Exhibit 10.6 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.10 +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Bruce H. Vincent (incorporated by reference as Exhibit 10.4 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.11 +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Joseph A. D Amico (incorporated by reference as Exhibit 10.3 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.12 +	Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Victor R. Moran (incorporated by reference as Exhibit 10.7 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.13 +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Alton D. Heckaman, Jr. (incorporated by reference as Exhibit 10.5 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).
10.14 +	Amended and Restated Employment Agreement dated as of May 9, 2001 between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Donald L. Morgan (incorporated by reference as Exhibit 10.8 to Swift Energy Company s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2001, File No. 1-08754).

10.15 +	Fourth Amended and Restated Agreement and Release by and between Swift Energy Company, predecessor to Swift Energy Operating, LLC, and Virgil Neil Swift, dated November 20, 2000 (incorporated by reference as Exhibit 10.13 to Swift Energy Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2000, File No. 1-08754).

10.16 +	Employee Stock Purchase Plan (incorporated by reference as Exhibit 4(a) to Swift Energy Company s Registration Statement No. 33-80228 on Form S-8 filed June 15, 1994, File No. 1-08754).
10.17 +	Description of non-employee directors compensation arrangements (incorporated by reference as Exhibit 10.16 to Swift Energy Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2004, File No. 1-08754).
10.18 +	Forms of agreements for grant of incentive and non-qualified stock options and forms of agreement for grant of restricted stock under Swift Energy 2001 Omnibus Stock Compensation Plan (incorporated by reference as Exhibit 10.17 to Swift Energy Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2004, File No. 1-08754).
10.19 +*	Forms of agreements for grant of incentive stock options and forms of agreement for grant of restricted stock under Swift Energy Company 2005 Stock Compensation Plan.
10.20+	Description of executive officers compensation arrangements (incorporated by reference as Exhibit 10.25 to Swift Energy Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2004, File No. 1-08754).
10.21	First Amended and Restated Credit Agreement effective as of June 29, 2004, among Swift Energy Company and Bank One, NA as Administrative Agent, Wells Fargo Bank, National Association as Syndication Agent, BNP Paribas, as Syndication Agent, Caylon, as Documentation agent, Societe Generale, as Documentation Agent and the Lenders Signatory Hereto and Banc One Capital Markets, Inc., as Sole Lead Arranger and Sole Book Runner (incorporated by reference as Exhibit 10.2 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-08754).
10.22	First Amendment to First Amended and Restated Credit Agreement effective as of November 1, 2005 by and among Swift Energy Company, JP Morgan Chase Bank, N.A. as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Sydication Agent, BNP

	Paribas, as Syndication Agent, Caylon, as Documentation Agent, and Societe Generale, as Documentation Agent. (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2005, File No. 1-08754).
10.23*	Second Amendment to First Amended and Restated Credit Agreement effective as of December 28, 2005, by and among Swift Energy Company and Swift Energy Operating, LLC, and J.P. Morgan Chase Bank, N.A., as Administrative Agent, J.P. Morgan Securities, Inc. as Sole Lead Arranger and Sole Book Runner, Wells Fargo Bank, National Association, as Syndication Agent, BNP PARIBAS, as Syndication Agent, Calyon as Documentation Agent and Societe Generale as Documentation Agent.
10.24	Eighth Amendment to Lease Agreement between Swift Energy Company and Greenspoint Plaza Limited Partnership dated as of June 30, 2004 (incorporated by reference as Exhibit 10.1 to the Swift Energy Company Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2004, File No. 1-08754).
12*	Swift Energy Company Ratio of Earnings to Fixed Charges
21*	List of Subsidiaries of Swift Energy Company.
23(a)*	The consent of H.J. Gruy and Associates, Inc.
23(b)*	Consent of Ernst & Young LLP as to incorporation by reference regarding Forms S-8 and S-3 Registration Statements.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1 *	The summary of H.J. Gruy and Associates, Inc. report, dated January 25, 2006.

* Filed herewith.

\+ Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant, Swift Energy Company, has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

SWIFT ENERGY COMPANY

By
:

A. Earl Swift
Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant, Swift Energy Company, and in the capacities and on the dates indicated:

Signatures	Title	Date
/s/ A. Earl Swift A. Earl Swift	Chairman of the Board	March 1, 2006
/s/ Terry E. Swift Terry E. Swift	Director Chief Executive Officer	March 1, 2006
/s/ Alton D. Heckaman Jr. Alton D. Heckaman Jr.	Executive Vice-President Principal Financial Officer	March 1, 2006
/s/ David W. Wesson David W. Wesson	Controller Principal Accounting Officer	March 1, 2006

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Signatures	Title	Date
/s/ Deanna L. Cannon	Director	March 1, 2006
Deanna L. Cannon		
/s/ Raymond E. Galvin	Director	March 1, 2006
Raymond E. Galvin		
/s/ Douglas J. Lanier	Director	March 1, 2006
Douglas J. Lanier		
/s/ Greg Matiuk	Director	March 1, 2006
Greg Matiuk		
/s/ Henry C. Montgomery	Director	March 1, 2006
Henry C. Montgomery		
/s/ Clyde W. Smith, Jr.	Director	March 1, 2006
Clyde W. Smith, Jr.		
/s/ Charles J. Swindells	Director	March 1, 2006
Charles J. Swindells		
/s/ Bruce H. Vincent	Director	March 1, 2006
Bruce H. Vincent		

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EXHIBIT INDEX

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32	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	The summary of H.J. Gruy and Associates, Inc. report, dated January 25, 2006.